In the United States Court of Appeals
FOR THE EIGHTH CIRCUIT

No. 24-2123(L)
Southwestern Electric Power Company; Utility Water Act Group,
Petitioners,

v.

United States Environmental Protection Agency; Michael S. Regan, Administrator, United States Environmental Protection Agency,
Respondents,

Clean Water Action, Sierra Club, Waterkeeper Alliance, Inc., Natural Resources Defense Council, Environmental Integrity Project, PennEnvironment, Inc. and Prairie Rivers Network,
Intervenor-Respondents.

On Petitions for Review from the
U.S. Environmental Protection Agency

UTILITY AND STATE PETITIONERS' MOTION FOR A STAY PENDING REVIEW

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Petitioners,

v.

United States Environmental Protection Agency; Michael S. Regan, Administrator, United States Environmental Protection Agency,

Respondents,

Clean Water Action, Sierra Club, Waterkeeper Alliance, Inc., Natural Resources Defense Council, Environmental Integrity Project, PennEnvironment, Inc. and Prairie Rivers Network,

Intervenor-Respondents.

No. 24-2215

City Utilities of Springfield, Missouri, by and through the Board of Public Utilities,

Petitioner,

v.

United States Environmental Protection Agency; Michael S. Regan, Administrator, United States Environmental Protection Agency,

Respondents,

Clean Water Action, Sierra Club, Waterkeeper Alliance, Inc., Natural Resources Defense Council, Environmental Integrity Project, PennEnvironment, Inc. and Prairie Rivers Network,

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TABLE OF ABBREVIATIONS

2015 Rule	*Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category*, 80 Fed. Reg. 67,838 (Nov. 3, 2015)
2020 Rule	*Steam Electric Reconsideration Rule*, 85 Fed. Reg. 64,650 (Oct. 13, 2020)
2024 Rule or "the Rule"	*Supplemental Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category*, 89 Fed. Reg. 40,198 (May 9, 2024)
AEP	American Electric Power
BAT	Best Available Technology Economically Achievable
CWA	Clean Water Act
ELGs	Effluent Limitation Guidelines
EPA	U.S. Environmental Protection Agency
IPM	Integrated Planning Model
Leachate	Combustion Residual Leachate
Scrubber Water	Flue Gas Desulfurization Wastewater
UWAG	The Utility Water Act Group

INTRODUCTION

The Clean Water Act (CWA) requires the U.S. Environmental Protection Agency (EPA) to establish "effluent limits" governing the discharge of pollutants from industrial sources, and periodically issue "guidelines" permit writers must follow in setting those limits. EPA must base its "effluent limitation guidelines" (ELGs) on limits that can be achieved through use of the "best" technology that is both "available" and "economically achievable." 33 U.S.C. § 1311(b)(2)(A).

In 2020, after study by two administrations, EPA set stringent ELGs for the wastewater coal-fired power plants generate in managing combustion by-products (e.g., ash). The agency evaluated a range of technologies for dealing with the high volumes and unique chemistry of power-plant wastewater, including membrane and evaporator systems that might entirely eliminate discharges of certain pollutants. The agency ultimately concluded these membranes and evaporators did not meet the statutory standard; they were not available nationwide (if at all) for this scale and use, were too costly, and carried unacceptable environmental impacts. The agency instead set effluent limits based on different technologies that use physical, chemical, and biological

approaches to remove pollutants from wastewater. That option was costly, too. EPA estimated the cost to plants nationwide would be over $200 million per year for 20 years. But that was less than half the cost of membranes and evaporators and, more importantly, the technology was available to meet the new limits.

Utilities then set out to acquire and install the systems necessary to comply. They could not afford to wait. It took years to obtain financing and approvals, design plant modifications, acquire and install equipment, and conduct testing. Soon they discovered EPA's cost estimates were wildly off the mark—almost uniformly low, sometimes by an order of magnitude.

One year and one Presidential election later, EPA decided to revisit those ELGs, this time proposing to set zero-discharge limits based on the same membrane and evaporator technologies it had just rejected. And even though the new treatment systems utilities were installing at great expense to meet the 2020 Rule's requirements might be rendered obsolete, EPA refused to suspend the 2020 Rule.

Why the change? The answer is simple—the new administration wanted to use all regulatory levers to force the retirement of coal-fired

power plants. Piling new, exorbitant wastewater treatment costs on top of the substantial costs just imposed was one such lever. In May 2024, EPA followed through, setting new ELGs that impose zero-discharge requirements. Power generators that already invested hundreds of millions on systems the 2020 Rule required now must spend that much again and more to continue operating plants beyond 2034.

The Rule is unlawful. As Petitioners will explain at the merits stage, EPA's turnabout is not based on a technological breakthrough or new evidence altering its previous conclusion. Using membranes and evaporators to try to eliminate discharges at critical baseload power plants presents real problems. EPA's dismissal of those problems is arbitrary and capricious—and relies on reading the word "available" contrary to its plain meaning.

Here, though, Petitioners focus on EPA's flawed analysis of the costs utilities and their ratepayers must bear. Specifically, EPA persisted in using the same flawed cost-projection model that materially underestimated compliance costs of the 2020 Rule. Confronted with the magnitude of its prior errors, EPA sidestepped the issue and failed to address the model's systemic flaws. Doubling down, EPA relied on the

demonstrably flawed 2020 cost estimates when it brushed aside Petitioners' profound reliance interests spurned by EPA's abrupt reversal of course.

Utility Petitioners will suffer irreparable harm absent a stay because, over the next year, they must spend millions of un-recoupable dollars to determine if it is possible at bearable expense to eliminate discharges with the dubious technology EPA now says is available for the task.[1] The States, too, will suffer, as the Rule threatens the reliability of their power grids and promises higher electricity rates for their citizens. The Court should stay the Rule.[2]

BACKGROUND

I. The Clean Water Act and Effluent Limit Guidelines

The CWA prohibits the discharge of "pollutants" from "point sources" into "waters of the United States" unless authorized. 33 U.S.C. § 1311(a). Facilities discharging wastewater must obtain a permit setting limits on discharges of pollutants. *Id.* § 1342. Those limits can be based on the amount of a pollutant the receiving water can handle

[1] Ex.1 , att.A.

[2] Utility Petitioners asked EPA to stay the Rule on June 17, 2024. EPA has not acted on the request. *See* Fed. R. App. P. 18(a)(2)(A)(ii).

without violating water-quality standards. *Id.* §§ 1312, 1342. And they can be based on the amount that can be discharged if the facility uses certain technology. *Id.* §§ 1314, 1342; *see Texas Oil & Gas Ass'n v. EPA*, 161 F.3d 923, 927 (5th Cir. 1998). This case concerns technology-based limits.

Permit writers do not set technology-based limits in a vacuum. Instead, EPA must periodically establish ELGs for "classes and categories of point sources." *See, e.g.*, 33 U.S.C. § 1314(b). The CWA prescribes different standards for setting ELGs based, among other things, on the age of the facilities and whether they discharge to publicly-owned treatment works or directly to waters of the United States. *See id.* §§ 1311(b), 1314(b), 1316(b)-(c); *see also Sw. Elec. Power Co. v. EPA*, 920 F.3d 999, 1006 (5th Cir. 2019).

Here, the relevant standard governs existing power plants that directly discharge to jurisdictional waters, and it requires EPA to base ELGs on limits attainable through use of the "best available technology economically achievable" (BAT). 33 U.S.C. §§ 1311(b)(2)(A), 1314(b)(2).[3]

[3] For indirect discharges, the Rule establishes pretreatment standards for existing sources that are the same as the BAT limits (with

To qualify as BAT, a technology must be both "available" and "economically achievable." *See Texas Oil*, 161 F.3d at 928. EPA must consider several factors, including "the cost of achieving such effluent reduction," to determine whether a technology satisfies those statutory requirements. 33 U.S.C. § 1314(b)(2)(B).

Congress envisioned that, as technology evolved, the ELG program would "result in reasonable further progress toward the national goal of eliminating the discharge of all pollutants." *Id.* § 1311(b)(2)(A). But at the same time, Congress empowered EPA to actually eliminate discharges after finding "such elimination is technologically *and* economically achievable for a category or class of points sources." *Id.* (emphasis added). Moreover, when identifying "control measures and practices available to eliminate the discharge of pollutants," EPA must "tak[e] into account the cost of achieving" complete elimination of the discharge of pollutants. *Id.* § 1314(b)(3).

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limited exceptions) and apply May 9, 2027. 89 Fed. Reg. 40,198, 40,200 (May 9, 2024).

II. EPA has undertaken successive ELG rulemakings targeting the steam electric utility sector.

This case involves EPA's most recent effort to set ELGs on discharges from coal-fired power plants. Coal-fired plants typically require high volumes of water for cooling and to manage ash produced during combustion. Many modern plants with air-emission control technology also use water to transport captured air pollutants. So today, coal-fired plants must manage not just the ash left after combustion, but also concentrated pollutants removed from their exhaust. Starting in 2015, EPA promulgated, reconsidered, promulgated again, and reconsidered again new and increasingly restrictive ELGs governing these wastestreams from coal-fired plants.

A. 2015 ELG Rule

In 2015, EPA issued a final rule revising the ELGs for power plants.[4] That rule addressed two wastestreams that are directly relevant here: (i) flue gas desulfurization wastewater ("Scrubber Water"); and (ii) combustion residual leachate ("Leachate"). *See* 80 Fed. Reg. at 67,846. Scrubber Water is produced by systems spraying a sorbent slurry to facilitate a reaction where sulfur dioxide is removed from exhaust gas

[4] 80 Fed. Reg. 67,838 (Nov. 3, 2015).

and taken away in the slurry water. *See id.*. Leachate is produced when water passes through coal ash, such as ash stored in a lined landfill. *See* 40 C.F.R. § 423.11(r).

EPA considered a variety of treatment technologies that might reduce or eliminate these wastestreams. EPA concluded that systems using chemical flocculants to allow pollutants to settle more quickly, coupled with biological systems that introduced microorganisms to consume certain pollutants, were BAT for treating Scrubber Water. 80 Fed. Reg. at 67,850. EPA found the technologies were available. And, although expensive (costing about $10 billion industry-wide across all wastestreams), they were economically achievable, too. *Id.* at 67,841.

EPA concluded that membranes and evaporators were not technologically available or economically achievable to deal with Scrubber Water. Similarly, the agency concluded thermal-evaporation systems—i.e., using heat either from the sun or external sources to separate water from solid pollutants—were only available in hot and dry climates and thus did not satisfy the statute's definition of availability. *Id.* at 67,850 n.21.

B. 2020 ELG Rule

In 2017, EPA announced it would reconsider its 2015 ELGs for Scrubber Water and bottom ash transport water. 82 Fed. Reg. 43,494 (Sept. 18, 2017). The agency was concerned about the cost of implementing the technologies needed to meet the ELGs it set for those wastestreams. It also wanted to consider whether plants could scale up "membrane" technology, such as reverse osmosis systems used to treat low-volume waste streams, to treat high-volume wastestreams at power plants to achieve zero liquid discharge of some pollutants.[5] Because reconsideration might make investments to implement the 2015 Rule unnecessary, the agency postponed 2015 Rule compliance deadlines. 82 Fed. Reg. at 43,496.[6]

EPA once again concluded that systems using a combination of chemical and biological treatment systems to facilitate physical removal of pollutants was BAT for Scrubber Water, although it identified a more cost-effective method for the system's biological component. And as before, EPA estimated utilities would be required to spend billions of

[5] Ex.2 at 4-4 to 4-5 (Suppl. TDD).

[6] The Fifth Circuit vacated the 2015 limits for Leachate and legacy wastewater. *See Sw. Elec. Power Co.*, 920 F.3d at 999.

dollars to comply with the new Scrubber Water limits.[7] With limited exceptions, it required facilities to implement compliant technologies no later than December 31, 2025.

EPA "carefully consider[ed]" and "reject[ed] membrane filtration" as BAT. First, "significant information gaps and uncertainties in EPA's record" precluded a finding that membrane filtration is technologically available to treat steam electric wastestreams nationwide. Second, "membrane filtration entails unacceptable non-water quality environmental impacts associated with management of the membranes' byproduct, brine." And third, "membrane filtration would result in higher costs to industry." 85 Fed. Reg. 64,650, 64,663 (Oct. 13, 2020).

Also, as it did in the 2015 Rule, EPA rejected thermal evaporation technologies as the basis for BAT limits for Scrubber Water due to especially high costs. *See id.* at 64,668. EPA found thermal technologies were 2.4 times the cost of chemical and biological systems, and 1.04 times the cost of membrane filtration. *See id.* at 64,669. And like membrane systems, "thermal technologies have unacceptable non-water quality

[7] Ex.3 at 3-9, Tbl.3-2.

environmental impacts associated with management of the resultant brine." *Id.* at 64,669.

EPA projected the costs to comply with its 2020 ELGs would be substantial, but later facts revealed that EPA had drastically underestimated those costs. For example, to treat Scrubber Water at American Electric Power's (AEP) Mitchell Plant, EPA estimated approximately $13 million in capital costs to install biological treatment.[8] In reality, it cost $48 million for AEP to implement those systems.[9] The same is true for Georgia Power Company's Plant Bowen, where EPA estimated approximately $28.6 million in capital costs to install a compliant treatment system,[10] while it actually cost "nearly $110 million."[11]

Significantly, utility experts tasked with designing and implementing such systems detailed, in comments on the 2020 Rule, why EPA's cost model was flawed. For one thing, EPA used the wrong "flow" figure for sizing equipment, using "average" flow instead of "peak" flow.[12]

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[8] Ex.4 at 22-29, Tbl.4 (FGD Wastewater Regulatory Option A).
[9] Ex.5, Company Exhibit BDS-D3.
[10] Ex.4 at 22-29, Tbl.4 (FGD Wastewater Regulatory Option A).
[11] Ex.6 at 26.
[12] Ex.7 at 2-2 to 2-3.

For another, EPA underestimated the cost to install equipment by systematically discounting "balance of plant" factors—i.e., the cost associated with site preparation, bonding and insurance, and tie-in of vendor equipment.[13] Lastly, EPA underestimated needed redundancies.[14]

C. 2024 ELG Rule

In August 2021, EPA announced it would revise the 2020 Rule, most notably its conclusions regarding membrane technology. 86 Fed. Reg. 41,801 (Aug. 3, 2021). The key facts were unchanged. There were no technological breakthroughs, and the cost was still exorbitant. But the new administration wanted to use all levers in the federal regulatory arsenal to reduce carbon emissions, especially after the Supreme Court held EPA lacked authority under the Clean Air Act to reduce carbon emissions by shifting generation away from fossil fuels. *West Virginia v.*

[13] *Id.* at 2-3 to 2-7.
[14] *Id.* at 2-7 to 2-8.

EPA, 597 U.S. 697 (2022).[15] Using ELGs to heap costs on coal plants was one such lever.[16]

Just so, in sharp contrast to its approach in 2017, EPA chose not to suspend the 2020 Rule's obligations as it reconsidered them. EPA required utilities to continue pouring money into 2020-Rule systems, even though the new rulemaking might render those systems obsolete. 86 Fed. Reg. at 41,801. That put electric utilities to a profound dilemma—keep spending millions on soon-to-be-obsolete treatment systems to meet the 2020 Rule's December 31, 2025 deadline or prematurely retire a reliable facility.[17]

EPA issued its final rule in May 2024 and determined membrane systems are BAT for Scrubber Water and Leachate. In addition to membranes, EPA concluded that thermal evaporation and spray dryer evaporators, "alone or in any combination" with membranes are now

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[15] Ex.8 at ED_006652_00039277-00001, ED_006652_00039279-00001 (new ELG rulemaking was part of a "cross-office power sector strategy" and the Office of Water was "excited to have robust discussions with OLEM, OAR, OP, and OGC about how the ELG might contribute [redacted].").

[16] *See* Ex.9.

[17] Petitioner Utility Water Act Group (UWAG) immediately raised these concerns to EPA in comments submitted October 14, 2021. Ex.10.

available to eliminate the discharge of both Scrubber Water and Leachate. 89 Fed. Reg. at 40,215, 40,225. And all of these technologies, deemed unavailable and too costly in 2020, are now deemed economically achievable even though their costs have not decreased—and even though those costs will now pile on top of those utilities are incurring already just to comply with the still-applicable 2020 Rule.[18]

Facilities must meet these new limits as soon as possible (but no later than December 31, 2029), unless they retire or repower by December 31, 2034. And by December 31, 2025 they must decide whether to make a run at implementing the technological changes necessary to meet the new limits, or give up and retire coal-fired generation. 89 Fed. Reg. at 40,285.[19]

Critically, EPA relied on the same flawed cost model it used for the 2020 Rule, even though commenters explained in detail how and why that model produced serious errors, including the same deficiencies that

[18] Ex.11 at 39, Tbl.8.

[19] Units seeking to comply with the 2024 Rule by committing to retire by 2034 must still satisfy the 2020 Rule's limits for Scrubber Water and bottom ash transport water no later than December 31, 2025, submit a notice by December 31, 2025, and cease coal combustion by December 31, 2034. 89 Fed. Reg. at 40,284-85.

rendered the model wholly unreliable in the 2020 Rule.[20] Commenters presented concrete proof in the form of the real-world, real-time 2020-Rule compliance costs utilities presented to State regulators and that utilities continued to incur. The degree of EPA's errors in 2020 is astounding:

Comparison of EPA Projections v. Post-2020-Rule Utility Figures[21]

Plant Name	EPA Estimated Costs for Biological Treatment + Adjustment for Chemical Precipitation		Utility Estimated Costs for Biological Treatment	
	Capital	O&M	Capital	O&M
Fort Martin (Units 1-2)	10,997,849	576,766	45,597,126	553,000
Trimble County (Units 1-2)	12,785,392	1,535,726	64,800,000	3,085,416
Mill Creek (Units 1-4)	5,560,844	442,871	68,000,000	3,069,562
Ghent (Units 1-4)	9,068,391	741,951	70,200,000	4,215,581
Mitchell (Units 1-2)	13,463,922	--	48,811,000	--

[20] *See* Ex.12 at 39-41.

[21] Ex.13 at 82-83.

But EPA did not bother to understand and correct the flaws in its model. Rather, EPA blithely acknowledged it had likely underestimated compliance costs for some facilities, speculated it may have overestimated costs for others, and (with no supporting explanation) asserted the cost-estimation methodology was "reasonable."[22]

Presented with data demonstrating serious deficiencies in its model, EPA did almost nothing. Nothing in the 2024 record indicates EPA modified its basic approach to estimating compliance costs based on the real world examples of the costs companies incurred or reported to their regulators.[23] In fact, EPA repeatedly refers to its previous cost analyses as if they are proven prototypes for analyzing costs, and notes it continued to use the same basic approach.[24]

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[22] *See, e.g.*, Ex.14 at 1188.

[23] Table A-1, attached to the 2024 Regulatory Impact Analysis, Ex.15, summarizes the "principal methodological changes EPA made to analyses of the costs and economic impacts of [the 2024] ELG rule as compared to the analyses of the 2020 rule and the 2023 proposal." But the only reference to compliance costs is how those costs were discounted and annualized. EPA identifies no other significant adjustments to its overall cost methodology.

[24] *See, e.g.*, Ex.15 at 3-1 ("EPA applied the same methodology used to analyze the 2015 and 2020 rules, as well as the 2023 proposed rule, to calculate industry-level annualized compliance costs."); *Id.* at 3-3 (similar); *Id.* at 4-5 (similar).

Although the agency adjusted one variable relating to zero discharge technologies,[25] those changes did not cure the fundamental problems undermining EPA's 2020 cost estimates. For example, EPA's model predicts Alabama Power Company's Plant Miller would spend $25.2 million in capital costs to meet the new zero-discharge limits.[26] But a third-party engineering firm concluded those costs would be approximately $279 million—*an order of magnitude greater*.[27]

EPA then compounded that error by feeding its erroneously-modeled cost estimates into a separate model—the Integrated Planning Model (IPM), on which EPA relies to assess the broader market effects of layering the 2020 Rule's costs on top of the 2024 Rule's costs. *See* 89 Fed. Reg. at 40,265. But by feeding that model flawed inputs, EPA undermined IPM's output and any conclusions EPA draws from it.

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[25] EPA specifically updated the methodology for brine encapsulation—the process of converting concentrated brine into solid waste—to increase the amount of fly ash and other materials needed to undertake the process successfully. 89 Fed. Reg. at 40,220.

[26] Ex.16.

[27] Ex.6 at 37 and App.A.

ARGUMENT

Courts consider four factors in determining whether to stay agency action pending judicial review: (1) the applicant's likelihood of success on the merits; (2) irreparable injury absent a stay; (3) the balance of equities among interested parties; and (4) the public interest. *Nken v. Holder*, 556 U.S. 418, 434 (2009). The Court must "'balanc[e]'" all four factors, *Brady v. Nat'l Football League*, 640 F.3d 785, 789 (8th Cir. 2011) (per curiam) (citation omitted), and "'[w]hile no single factor is determinative, the probability of success factor is the most significant,'" *Cigna Corp. v. Bricker*, 103 F.4th 1336, 1342 (8th Cir. 2024) (citation omitted). "'[W]here the movant has raised a substantial question and the equities are otherwise strongly in his favor, the showing of success on the merits can be less.'" *Nebraska v. Biden*, 52 F.4th 1044, 1046 (8th Cir. 2022) (per curiam) (quoting *Dataphase Sys., Inc. v. C L Sys., Inc.*, 640 F.2d 109, 113 (8th Cir. 1981) (en banc)). Here, each factor favors a stay.

I. Petitioners are likely to prevail on the merits.

This Court must set aside agency action that is "arbitrary, capricious, an abuse of discretion, or otherwise not in accordance with law." 5 U.S.C. § 706. An agency acts arbitrarily when it ignores "an

important aspect of the problem," or when it fails to provide "a satisfactory explanation for its action." *Motor Vehicle Mfrs. Ass'n of the U.S., Inc. v. State Farm Mut. Auto. Ins. Co.*, 463 U.S. 29, 43 (1983); *accord Nebraska v. EPA*, 812 F.3d 662, 666 (8th Cir. 2016). When confronted with facts confounding a central premise of the agency's proposed action, the agency cannot "sidestep" those facts. *Ohio v. EPA*, 144 S.Ct. 2040, 2054–55 (2024). It instead must engage them and either adjust its approach or provide a reasoned explanation for why the facts do not matter. *Id.*

EPA's action here is unlawful for multiple reasons, not least of all because EPA has applied a definition of "available" at odds with the plain meaning of that word. "Available" means "present or ready for immediate use," "accessible," or "obtainable." *Merriam-Webster's Collegiate Dictionary* (11th ed. 2020) (*Merriam-Webster*). Membranes and evaporators are not available to actually (and if so reliably) achieve zero discharge limits. Data gaps persist, and EPA has not grappled with the significant and likely insuperable problems of scaling up these systems and applying them to the challenging volume, flow rate, and chemistry of wastestreams at large baseload plants. In EPA's view, it

can gloss over these problems, because the statute allows it to "force" technology. Under this reading, it suffices if it is merely "possible" that membranes and evaporators used elsewhere could be scaled up and deployed at covered facilities to achieve zero discharge limits at some indeterminate point in the future. 89 Fed. Reg. at 40,202, 40,216. But wishing into existence systems not actually available to achieve the desired limits goes well beyond forcing the use of available technology. And the agency's failure carefully to examine the impediments to applying these technologies at power plants—especially in light of the exorbitant cost and EPA's flip-flop on the question—is arbitrary and capricious.

For now, though, it's enough to note the glaring deficiency in how EPA tackled the "economic achievability" part of its statutory inquiry. Specifically, notwithstanding substantial real-world data revealing significant flaws in EPA's model for estimating compliance costs, EPA persisted in using that model with no meaningful correction. By failing to forthrightly engage contrary data, EPA poisoned the entire Rule for two reasons.

A. EPA arbitrarily sidestepped demonstrated errors in its cost-estimation methodology.

Accurately assessing the cost of installing and operating treatment technology is at the very heart of EPA's statutory duty here. The statute expressly directs EPA to select only technologies that are "economically achievable" and specifically instructs EPA to consider "the cost of achieving such effluent reduction." 33 U.S.C. §§ 1311(b), 1314(b)(2)(B). And fair evaluation of the cost of regulation is essential to reasoned decision-making. *Michigan v. EPA*, 576 U.S. 743, 753, 759 (2015).

EPA had a perfect opportunity to fairly assess how its 2020 cost projections matched the costs industry was then incurring. EPA asked larger utilities to provide that information,[28] and most did.[29] And as noted above, the data showed just how poorly EPA's projection matched reality. At that point, EPA was obliged to engage the confounding data meaningfully. *See, e.g., Wild Virginia v. U.S. Forest Serv.*, 24 F.4th 915, 927–28 (4th Cir. 2022) (finding agency action arbitrary and capricious when real-world data differed materially from results predicted by agency's model); *Zen Magnets, LLC v. Consumer Prod. Safety Comm'n*,

[28] *See, e.g.*, Ex.17.
[29] *See, e.g.*, Ex.18.

841 F.3d 1141, 1149 (10th Cir. 2016) (agency must take into account changes in data underlying its action). But in response, EPA did no such thing. It instead made excuses, complaining that utilities had provided their data in the wrong format or with insufficient specificity.[30] Leave aside EPA's failure to request the data in any particular format—it easily could have served utilities follow-up requests for data to be delivered in precisely the format EPA needed. That never happened.

Ultimately, the most EPA did was acknowledge "it may have underestimated compliance costs for some plants."[31] But acknowledging a problem is not the same as actually engaging it. *Ohio*, 144 S.Ct. at 2054–55 ("[A]wareness is not itself an explanation."). And there is no evidence EPA conducted any analysis to better understand the margin of error in its previous analysis, why its estimates were so wide of the mark, or why it remained appropriate to rely on a cost-estimation methodology that was so obviously flawed. So, it is no surprise that, in support of its conclusion that "EPA's cost estimates provide a reasonable estimate for purposes of determining economic achievability," the only explanation it

[30] Ex.14 at 1188.
[31] *Id.*

can provide is the speculation that "it may have … overestimated costs for other plants."[32] That is classic "sidestepping," and it falls well short of an agency's obligation when confronted with data confounding its analysis. *Ohio*, 144 S.Ct. at 2055.

B. EPA failed to adequately account for the substantial costs incurred in reliance on the 2020 Rule.

When an agency changes course, it must understand the reliance interests its previous policy engendered. *See Dep't of Homeland Sec. v. Regents of the Univ. of California*, 591 U.S. 1, 30 (2020). The agency must "assess whether there were reliance interests, determine whether they were significant, and weigh any such interests against competing policy concerns." *Id.* at 33. When reliance interests are significant, EPA must provide a "more detailed justification" for its action. *FCC v. Fox Television Stations, Inc.*, 556 U.S. 502, 515 (2009).

EPA acknowledged that its 2024 reversal of decisions made in 2020 obligated it to understand these reliance interests.[33] But the first step toward meeting that obligation was to understand the magnitude of industry's reliance interests—i.e., the costs incurred to comply with the

[32] *Id.*
[33] 89 Fed. Reg. at 40,219.

2020 Rule—and how those reliance costs might affect the economic achievability of zero-discharge technology. EPA did not even begin to meet that obligation.

Yes, EPA collected data on what utilities spent to comply with the 2020 Rule. But EPA then disregarded that data in evaluating how stacking the cost of zero-discharge technology on top of 2020-Rule costs would affect the utility sector as a whole. Instead, EPA simply plugged the rosy estimates from 2020 into IPM, which then predicted the results on regulated utilities wouldn't be so bad.[34] That is not a fair assessment of the significance of the actual reliance interests. It is instead an assessment of the hypothetical costs industry might have incurred had EPA's cost-estimation model been accurate. At most, EPA demonstrated "awareness" that industry had incurred costs in reliance on the 2020 Rule. But it also was required to understand and account for the significance of those costs, *Ohio*, 144 S.Ct. at 2054–55, and explain in detail why they are justified, *Fox Television*, 556 U.S. at 515. EPA failed to do so, making its action arbitrary and capricious.

[34] *Id.*

II. Petitioners will suffer irreparable harm absent a stay.

The Rule requires Utility Petitioners to spend massive sums of money starting right now.

By December 2025, the Rule forces Petitioners to choose between (1) installing unproven zero-discharge technologies within five years or (2) retire coal combustion altogether. Ex.1 ¶16; Ex.19 ¶13; Ex.20 ¶12. So Petitioners must immediately pour money into researching and evaluating whether using zero-discharge technologies is even possible—not to mention economically viable—at their plants. Ex.1 ¶¶20-25; Ex.19 ¶40; Ex.21 ¶25.

No matter which option Petitioners choose, they will incur substantial compliance costs in the coming months. Ex.1 ¶55; Ex.19 ¶¶22-24; Ex.21 ¶25. If Petitioners determine zero-discharge technologies are viable, they will need to immediately begin spending millions of dollars in engineering and equipment procurement costs to install and operate those technologies by 2029. Ex.1 ¶29 (estimating constructing and operating zero-discharge technologies at three plants will cost over $900 million during the first ten years of operation); Ex.19 ¶41 (estimating 50% of its $100-130 million price tag on zero-discharge

technologies would be incurred in 2025 and 2026); Ex.20 ¶23. If Petitioners instead elect to retire their coal-fired units—a decision that is effectively irreversible once made—they will need to immediately spend money on portfolio modeling to secure replacement generation, Ex.1 ¶¶30-32, 35; Ex.19 ¶42; Ex.21 ¶32, and then begin constructing or acquiring generation resources to satisfy EPA's timeline. Ex.1 ¶¶32-35; Ex.19 ¶42; Ex.21 ¶¶29-31.

The Rule's deadlines do not allow Petitioners time to wait for the Court to reach a decision on the merits. Ex.1 ¶56; Ex.19 ¶46; Ex.21 ¶36. If Petitioners wait for a favorable decision on the merits, the money spent on labor, custom-designed plant equipment, consulting, technology evaluation, portfolio modeling, permitting, engineering, site selection, fuel procurement, and financing cannot be recouped or refunded. Ex.1 ¶55; Ex.19 ¶45; Ex.21 ¶35. These "certain," "great," and "imminen[t]" costs will be unrecoverable absent a stay and present "a clear and present need for equitable relief." *Iowa Utilities Bd. v. F.C.C.*, 109 F.3d 418, 425 (8th Cir. 1996); *see also Thunder Basin Coal Co. v. Reich*, 510 U.S. 200, 220–21 (1994) (Scalia, J., concurring in part and in the judgment).

The Rule also could harm Petitioners' reputations with their customers. Ex.1 ¶¶40-46, 58; Ex.20 ¶11; Ex.19 ¶¶28, 45; *see Iowa Utilities Bd.*, 109 F.3d at 426 ("[T]he petitioners' potential loss of consumer goodwill qualifies as irreparable harm."). The massive costs imposed by the Rule inevitably will lead to increased utility rates, and forced retirement could undermine reliability of electricity. Whatever option Petitioners choose, they will be stuck with the stranded costs of installing millions of dollars in equipment the 2020 Rule requires but the new Rule renders prematurely obsolete. Ex.1 ¶38; Ex.19 ¶43; Ex.21 ¶20; Ex.22 ¶¶8, 10.

Finally, the Rule harms the State Petitioners' substantial interest in reliable, affordable electricity. Ex.23 ¶¶5-17; Ex.24 ¶¶4-7; Ex.25; *see also West Virginia v. EPA*, 90 F.4th 323, 331 (4th Cir. 2024) (citizens harmed by "rate hikes" occasioned by compliance costs); *Hoosier Energy Rural Elec. Coop., Inc. v. John Hancock Life Ins. Co.*, 588 F. Supp. 2d 919, 934 (S.D. Ind. 2008) (If a plant's ability to "provide power to … homes, farms, businesses and industries … is imperiled, so may be its ability to fulfill its mission to the public.").

III. The public interest and balance of the equities weigh in favor of a stay.

When "the Government is the opposing party," the Court's analyses of the third and fourth factors merge. *Nken*, 556 U.S. at 435. Both favor a stay.

A stay serves the public interest because the Rule stands to increase energy costs, decrease grid reliability, and prematurely shutter vital plants. Utilities must commit hundreds of millions of dollars to try to comply with the Rule, Ex.1 ¶29; Ex.19 ¶26; Ex.21 ¶¶20-21, and consumers ultimately will absorb much of that staggering price tag, spiking the average household electricity bill in some of the country's poorest regions. Ex.1 ¶¶29, 52; Ex.19 ¶19; Ex.21 ¶¶7-8; Ex.23 ¶18; Ex.24 ¶7; Ex.25. Or, if Petitioners opt to retire their coal-fired plants altogether, they will exacerbate legitimate reliability concerns. Ex.1 ¶¶40-46; Ex.20 ¶25; Ex.23 ¶¶8-15. Retirement will also devastate entire communities, destroying thousands of jobs and the economic stimulus they provide. Ex.1 ¶48; Ex.20 ¶9.

In contrast, a stay would cause negligible harm to the agency's interests. At most a stay would delay the deadline by which Petitioners must decide between investing millions of dollars in unproven

technologies and retiring altogether. But during the period of any stay, Petitioners must comply with the already-stringent requirements of the 2020 Rule.

CONCLUSION

For the foregoing reasons, the Court should grant a stay pending a determination on the merits.

July 26, 2024

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CERTIFICATE OF COMPLIANCE

I hereby certify that the foregoing Petitioners' Utility and State Motion for A Stay Pending Review complies with the type-volume limitation of Federal Rules of Appellate Procedure 27(d) and 32(a) because it contains 5179 words. This Motion complies with the typeface and the type style requirements of Federal Rules of Appellate Procedure 27(d) and 32(a) because this brief has been prepared in a proportionally spaced typeface using Word 14-point Century Schoolbook typeface.

Dated: July 26, 2024

/s/ *George P. Sibley, III*
George P. Sibley, III

CERTIFICATE OF SERVICE

I hereby certify that on this 26th day of July 2024, the foregoing Utility and State Petitioners' Motion for A Stay Pending Review Corporate was electronically filed with the Clerk of Court for the U.S. Court of Appeals for the Eighth Circuit by using the CM/ECF system.

I further certify that all participants in the case are registered CM/ECF users and that service will be accomplished by the CM/ECF system.

/s/ *George P. Sibley, III*
George P. Sibley, III

INDEX OF EXHIBITS

Ex. 1	Declaration of Gary O. Spitznogle, Vice President, Environmental Services, American Electric Power Company (July 25, 2024)
Ex. 2	EPA, Supplemental Technical Development Document for Revisions to the Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category (Aug. 2020) (Excerpts)
Ex. 3	EPA, Regulatory Impact Analysis for Revisions to the Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category (Aug. 28, 2020) (Excerpts)
Ex. 4	Eastern Research Group, Inc., *Generating Unit-Level Costs and Loadings Estimates by Regulatory Option – DCN SE08638* (Aug. 31, 2020) (Excerpts)
Ex. 5	Direct Testimony of Brian D. Sherrick on behalf of Appalachian Power Company and Wheeling Power Company, Public Service Commission of West Virginia, Company Exhibit BDS-D3
Ex. 6	Comments of The Southern Company on Supplemental Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category; Proposed Rule (May 30, 2023)
Ex. 7	Comments of the Electric Power Research Institute (EPRI) on EPA's Proposed ELG Rule (Jan. 20, 2020) (Excerpts)
Ex. 8	EPA Response to Utility Petitioners' Freedom of Information Act Requests (Excerpts)
Ex. 9	Friedman, Lisa, *E.P.A. Describes How It Will Regulate Power Plants After Supreme Court Setback*, N.Y. Times (July 7, 2022)
Ex. 10	Comments of the Utility Water Act Group (UWAG) in Response to EPA's Notice of Availability of the Preliminary Effluent Guidelines Program Plan 15 (Oct. 14, 2021)
Ex. 11	EPA, Technical Development Document for Final Supplemental Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category (Apr. 2024) (Excerpts)

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Ex. 12	Comments of the Electric Power Research Institute (EPRI) on EPA's Proposed Effluent Limitations Guidelines Rule (May 26, 2023) (Excerpts)
Ex. 13	Comments of the Utility Water Act Group (UWAG) on EPA's Proposed Rule; Supplemental Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category (May 30, 2023) (Excerpts)
Ex. 14	EPA, Response to Public Comments for Supplemental Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category (Apr. 2024) (Excerpts)
Ex. 15	EPA, Regulatory Impact Analysis for Supplemental Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category (Apr. 18, 2024) (Excerpts)
Ex. 16	EPA, Unit-level Costs and Loadings Estimates for the 2024 Final Rule (DCN SE11756A1) (EPA-HQ-OW-2009-0819-10336att1), Tab 2, lines 11-14
Ex. 17	Letter from Robert K. Wood, Director of the Engineering & Analysis Division of EPA's Office of Water, to Donna B. Hill, Principal Scientist at Southern Company (Dec. 13, 2021)
Ex. 18	Letter from Donna B. Hill, Principal Scientist at Southern Company, to Robert K. Wood, Director of the Engineering & Analysis Division of EPA's Office of Water (Apr. 1, 2022)
Ex. 19	Declaration of Craig Grooms, Chief Operating Officer, Buckeye Power, Inc. (July 23, 2024)
Ex. 20	Declaration of J. Michael Brown, Environmental Safety and Health Director, Ohio Valley Electric Corporation (June 20, 2024)
Ex. 21	Declaration of Jack Alvey, President & Chief Executive Officer, Indiana Municipal Power Agency (July 9, 2024)
Ex. 22	Declaration of Heath Lovell, President, Hallador Power Company, LLC (July 26, 2024)
Ex. 23	Declaration of James F. Huston, Chairman, Indiana Utility Regulatory Commission (July 23, 2024)

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Ex. 24	Declaration of R. Bruce Scott, Former Deputy Secretary of the Kentucky Energy and Environmental Cabinet (July 23, 2024)
Ex. 25	Georgia Public Service Commission, Resolution in Support of a Stay Motion on EPA's New Directives on ELG (July 24, 2024)

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EXHIBIT 1

Declaration of Gary O. Spitznogle, Vice President, Environmental Services, American Electric Power Company

I, Gary O. Spitznogle, declare as follows:

1. I am the Vice President, Environmental Services at American Electric Power Company (AEP). I am over the age of 18 years, and I am competent to testify concerning the matters in this declaration. I have personal knowledge of the facts set forth in this declaration, and if called and sworn as a witness, could and would competently testify to them.
2. I have nearly 3 decades of experience in electricity generation, and I have been employed at AEP since 1997. I hold a Bachelor of Science degree in Chemical Engineering with an environmental option from the Ohio State University, and I have completed the AEP/OSU Strategic Leadership Program.
3. As Vice President of Environmental Services at AEP, I am responsible for providing insight and direction into development of environmental policy, assuring compliance and overseeing environmental support for all AEP generation and energy delivery facilities.
4. AEP is a member of the Utility Water Act Group ("UWAG"). This declaration is submitted in support of the litigation challenging EPA's final rule entitled Supplemental Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category, 89 Fed. Reg. 40,198 (May 9, 2024) ("the 2024 ELG Rule" or "the Rule")).
5. I am familiar with AEP's operations, including generation and transmission, regulatory compliance, workforce management, and electric markets in general. I also am familiar with the Rule, and I am familiar with how the Rule will affect AEP's various operating companies, as well as its suppliers, members, consumers, and employees.
6. AEP is one of the largest electric utilities in the United States, delivering electricity to approximately 5.6 million customers in 11 states. AEP ranks among the nation's largest generators of electricity, owning 23,308 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).
7. In AEP's opinion, EPA's efforts to develop reasonable and cost-effective revisions to the steam electric effluent guidelines have failed. EPA's representation of the affordability and effectiveness of the proposed technologies for the subject wastewaters is grossly overstated and, absent a Stay, the Rule's timeline for making decisions about which compliance strategy to pursue will adversely affect AEP, our customers, and the reliability of the electric grid.

EPA's Recent Suite of Rules Targeting Electric Utilities

8. US EPA recently released four major new rules directed at the electric utility industry – the Greenhouse Gas (GHG) Rule, the ELG Rule, the Legacy Coal Combustion Residuals (CCR) Rule, and the revised Mercury Air Toxics Standards (MATS) Rule.

9. According to a US EPA press release from April 25, 2024, the "[f]our final rules deliver on the Biden-Harris Administration's day-one commitment to lead on climate action and to protect all communities from pollution."[1] That same press release says that, "[b]y announcing these final rules at the same time, EPA is following through on the commitment that Administrator Michael S. Regan made to industry stakeholders … to provide regulatory certainty as the power sector makes long-term investments in the transition to a clean energy economy. The standards are designed to work with the power sector's planning processes, providing compliance timelines that enable power companies to plan in advance to meet electricity demand while reducing dangerous pollution."[2] It goes on to say that "[b]y developing these standards in a clear, transparent, inclusive manner, EPA is cutting pollution while ensuring that power companies can make smart investments and continue to deliver reliable electricity for all Americans."[3]
10. This coordinated approach to regulation – arguably, the first of its kind by EPA (or perhaps by any agency) – simultaneously targeting a single industry with several major new rules under several separate statutes, is precisely why implementation of any of them must be stayed until there is certainty regarding all of them.
11. Currently, there is no "regulatory certainty" (EPA's words) to allow the power sector to make long-term investments.
12. If utilities are to make "smart investments and continue to deliver reliable electricity for all Americans," (EPA's words) and if these new standards are truly "designed to work with the power sector's planning processes" by "providing compliance timelines that enable power companies to plan in advance to meet electricity demand," (again, EPA's words) utilities must have the complete picture of what each of these major rules will ultimately require of them. AEP and its peers simply cannot make informed decisions about the future state of our generating fleet without understanding all of the requirements that will apply.
13. Each of these new rules will either impose millions, or perhaps billions, of dollars in compliance costs, or will require AEP to retire plants as the alternative compliance strategy. Yet, each of these rules is or is likely to be litigated, meaning the ultimate requirements of each rule are unknown. The GHG Rule is already being challenged by more than half the states and many utilities and trade associations, with 12 separate appeals having been consolidated before the United States Court of Appeals for the District of Columbia Circuit. The ELG Rule has been challenged in multiple federal jurisdictions and those appeals have been consolidated as well, before the United States Court of Appeals for the Eighth Circuit. The MATS Rule is similarly being challenged by 23 states and several utilities and other companies through four separate appeals. Until utilities have certainty as to the final requirements of all of these rules, which EPA intentionally released as a package to provide a big picture of all of the environmental obligations applicable to power generators so utilities could make informed decisions and "plan in advance to meet electricity demand" going forward, utilities simply cannot make the types of decisions that any of these rules individually requires. For this reason alone, this court should stay the requirements of the ELG Rule until there is certainty about all of the rules.

[1] Biden-Harris Administration Finalizes Suite of Standards to Reduce Pollution from Fossil Fuel-Fired Power Plants | US EPA
[2] *Id.*
[3] *Id.*

14. Even without considering the big picture impacts of all of the rules, the issues posed by compliance with the ELG Rule on its own in the near term warrant a stay.

Overview of Final ELG Rule

15. EPA's steam electric ELGs regulate specific wastestreams and pollutants from coal-fired electric generating units through binding conditions imposed in a facility's National Pollution Discharge Elimination System (NPDES) permit issued under the Clean Water Act (CWA). EPA establishes nationwide limits for these wastestreams based on the Best Available Technology Economically Achievable (BAT). In general, EPA has determined in the Rule that a suite of zero-discharge treatment systems (membrane filtration and thermal or spray dryer evaporation) are technologically available and economically achievable for the steam electric industry and therefore EPA has established zero liquid discharge (ZLD) limits for flue gas desulfurization wastewater (FGDW), bottom ash transport water (BATW), and combustion residual leachate (CRL). EPA also establishes more stringent limits for legacy wastewater (LWW) based on a determination that chemical precipitation is BAT for this wastestream.
16. Facilities must meet these limits as soon as possible (ASAP), but no later than Dec. 31, 2029, unless they choose to retire or repower by December 31, 2034. The choice to retire the unit and avoid costly ZLD modifications must be made December 31, 2025. This five-year compliance schedule in the rule is not enough time to implement the required technologies. This timeline is not reasonable and requires AEP to take actions now that will result in harm to AEP that can't be remedied if AEP is ultimately successful in this litigation.
17. According to EPA, the typical timeframe to raise capital, plan and design systems (including any necessary pilot testing), procure equipment, and construct and test systems falls well within the existing five-year permit cycle.[4] EPA noted that while plants may not need five years to comply with the limitations, the ''no later than'' date creates an outer boundary beyond which no discharger may seek additional time and creates a level playing field regarding the latest date. Therefore, EPA is requiring that any final limitations be achieved ''no later than'' December 31, 2029.
18. Alternatively, as noted above, AEP could elect to retire a plant by December 31, 2034, under the Rule's Permanently Ceasing Coal Combustion (PCCC) subcategory. That compliance option requires AEP to notify the agency of its binding commitment to permanently cease coal combustion by the end of next year – less than 18 months from now. Units that qualify for the 2034 PCCC subcategory are subject to the no discharge limit for FGDW and BATW after Apr. 30, 2035, and subject to mercury and arsenic limits for CRL no later than Apr. 30, 2035. Units seeking to qualify for the 2034 PCCC subcategory must satisfy the 2020 Rule's limits for FGDW and BATW no later than December 31, 2025, submit a Notice of Planned Participation (NOPP) by December 31, 2025, and cease coal combustion by December 31, 2034.

[4] 88 Fed. Reg. at 18862.

AEP And Its Operating Companies Are Irreparably Harmed If the ELG Rule Is Not Stayed Pending The Litigation

Steps Taken to Comply with the Rule by Installing New and Unproven Technologies During the Pendency of This Litigation Will Harm AEP Even If the Utility Petitioners Prevail

19. AEP has five power plants where major and/or novel technologies would need to be deployed to meet the requirements of the ELG Rule. Appalachian Power Company (APCo) is the most significantly affected of AEP's operating companies, as it requires membrane filtration ZLD treatment on FGD wastewater at all of its coal plant sites. APCo has three coal fired power plants which provide 4,270 MW of APCO's nameplate generating capacity – rougly 64%. Accordingly, regardless of whether APCo elects to install the new technologies or comply through PCCC, the Rule will have a substantial impact on APCos operations. These impacts will ultimately be felt by the consumers in APCo's service territory – all of whom depend on reliable generation to power their homes and keep them warm during frigid winters or cool during scorching summers.
20. Attempting to comply with the rule's ZLD requirements requires AEP to take steps now, incurring costs and accepting risks of noncompliance if the technology does not work; these harms cannot be reversed if AEP is successful in this litigation.
21. The Rule requires a zero-discharge approach based on chemical precipitation and membrane filtration as Best Available Technology (BAT) for FGD wastewater. The deadline for this limitation is as soon as possible, but no later than December 31, 2029.
22. Based on AEP's experience with projects of similar scale and complexity, and with deployment of unproven technology, the rule's five-year compliance schedule may not be enough time to implement a membrane filtration ZLD treatment for FGD wastewater. Absent a stay, AEP must take steps now if it stands any chance of implementing this technology by the rule's deadline.
23. As explained in our comments on the proposed rule, AEP does not believe membrane filtration is a tried and proven technology to be applied as an industry-wide treatment technology for FGD wastewater applications. More site-specific evaluation and testing are needed to truly understand the capabilities, limitations, and scope of the work necessary to implement the technology and any ancillary equipment needed for its support. However, the Rule's compliance schedule does not provide enough time to perform this type of site-specific work. AEP must enter into contracts and pay for design and construction of this technology now. As a result, AEP will incur significant costs that we may be unable to recover from customers or that may result in customers paying for equipment that they did not need to.
24. AEP recently installed bioreactor and ultrafiltration technologies required under the 2020 Rule, which were major capital projects at APCo's Amos, Mitchell and Mountaineer Plants. Those projects, which were "off the shelf" proven technologies, with ample data about their performance and reliability, still took 4 years and roughly $94 million to complete. Conversely, there is virtually no relevant data from comparable applications of advanced membrane and ZLD technologies that AEP can rely on when selecting and designing membrane based ZLD systems for any of our plants. As a result, AEP must do significant additional engineering and design work on the front end, as well as additional debugging on the back end before such a system can be operational. These major capital installation projects are likely to take a minimum of five years, however, given the relatively novel nature of the membrane filtration ZLD technology

prescribed by the Rule, additional time will be required for piloting and technology selection. These necessary steps take additional time not clearly knowable beforehand, which the Rule does not provide. As a result, absent a stay, AEP must make commitments of hundreds of millions of dollars to pursue unproven membrane filtration ZLD technology without having sufficient information to properly design the installations for each plant. If novel technology should fail to perform adequately, which cannot be foreseen at this point in time, AEP will have spent not only hundreds of millions of dollars on technology that is not suited to the task, it will also be faced with the inability to comply by the Rule's requirements by the deadline. Expenses of this magnitude will be heavily scrutinized by our regulatory commissions, which are unlikely to allow recovery for expenses of systems that do not work.[5]

25. Time and technical expertise from third parties is needed to produce reliable designs, cost estimates, and "balance of plant" modification details necessary to integrate the membrane filtration ZLD technology into an existing plant site. Economic evaluations are needed to determine if committing the necessary funding is reasonable. Beyond that point, equipment must be specified, bid and purchased under contracts, fabricated and delivered. These evaluations all take considerable time. Based on my experience and engineering judgment, I anticipate the time necessary to complete all of these activities and implement a reliable solution to meet the requirements of the 2024 ELG rule would be longer than what was needed for the proven and simpler projects completed at these same power plants to comply with the 2020 ELG Rule. AEP also has concerns that the significant increase in demand for membrane technology precipitated by this rule would further stress the supply chain and lead to additional delays. All of this requires AEP to begin procurement immediately if it hopes to be able to comply with the rule within five years.

26. I have prepared an outline describing why steam electric power plants, including AEP facilities, are harmed by the risk of loss of substantial costs and time evaluating whether the unproven technology on which the 2024 ELG Rule is premised can be successfully designed, acquired, installed and operated to meet the zero discharge requirements and deadlines of the Rule, attached hereto as Attachment A.

27. There are also risks inherent in obtaining regulatory approval for the costs of such technology. As a regulated utility, AEP can only recover the costs of a project if that project is deemed prudent and the expenses are approved by our public service commissions.

28. In December 2020, APCO submitted to the West Virginia Public Service Commission (WV PSC) a request for rate recovery to allow AEP to acquire, install, and operate equipment necessary to comply with the 2020 ELG Rule. The submission reflected significant analysis and investigation of the technologies and compliance options for three coal-fired power plants in West Virginia. One of those plants, the Mitchell Plant, is 50/50 co-owned by APCO and Kentucky Power Company (KPCO). In the case of Mitchell Plant, the biological system to treat FGDW cost approximately $48 million. The WV PSC approved rate recovery for this system in August 2021, whereas the Kentucky PSC declined to approve it, meaning the entire cost is being carried by West Virginia rate payers. Similar regulatory outcomes will mean that West Virginia customers will again have to carry the entirety of the 2024 ELG Rule retrofits at Mitchell Plant.

[5] See discussion below, re: regulatory disapprovals for past ELG expenses.

29. In total, AEP estimates that compliance with the new rule, not to mention the other new rules, will cost customers over $900 million during the first ten years of operating the new treatment technology (2029-2039) at its three West Virginia plants -- Amos, Mitchell, and Mountaineer. This $900 million estimate includes both the capital cost to construct new control technologies and the cost to operate these systems over that period. ELG costs at these plants are currently borne by customers in West Virginia and Virginia. AEP must now go back to these same regulators, a mere four years after WV PSC approved $94 million for the bioreactors needed to comply with the 2020 ELG Rule, to seek approval for this additional expense for a largely unproven technology, which will cause the average residential household bill in these two states to increase by an estimated $42-$60 per year.

<u>If AEP is forced to elect to Permanently Cease Coal Combustion before this litigation has completed, AEP is harmed, even if the utility petitioners ultimately prevail in their challenges to this rule.</u>

AEP will incur significant costs to procure replacement generation

30. If AEP cannot obtain regulatory approval, or if AEP determines its best compliance strategy is to comply with the Rule by electing to permanently cease coal combustion (PCCC), AEP must take action now, during the pendency of this litigation, to identify and procure replacement generation to ensure grid reliability into the future. As stated previously, the commitment for PCCC must be made by end of 2025. The planning to ensure adequate resources takes many years and, once a plan is put into place, cannot be easily changed.
31. AEP cannot depend solely on renewables and battery backups for baseload generation. Given the limitations of renewable generation associated with its intermittent and non-dispatchable (i.e., non-controllable) nature, AEP will have to look to other generation sources to provide replacement generation for the baseload power that AEP will lose if it elects to permanently cease coal combustion at any of its plants.
32. AEP must immediately begin spending money across several expense categories, to design and procure replacement generation. As noted in the introductory portion of this declaration, this is complicated by EPA's new GHG Rule and the uncertainties inherent in its ultimate requirements, given the numerous legal challenges to that rule that are pending.
33. Under EPA's new GHG Rule, new baseload (i.e., high capacity factor) generation that is gas or coal would have to install carbon capture and sequestration (CCS) technology, which is unproven and uneconomical. Therefore, the only technically viable option under the GHG Rule to replace baseload, dispatchable coal-fired generation within the timeframe needed[6] is to use a large number of low-capacity factor simple-cycle combustion turbines (CTs) all running at a capacity factor of 20% or less, or more expensive combined-cycle plants limited to 40% capacity factors. Whatever the combination of new power plants, these low capacity factor limitations means that customers will be paying for up to five times the number of new power plants than would be needed absent the very broken GHG Rule, with zero reduction in overall GHG emissions.
34. Low-capacity factor gas peaking generators combined with market purchases and/or renewables are in no way an adequate or equivalent replacement generation resource for high-capacity factor, dispatchable, load-following, baseload generation resources. Furthermore, for

[6] Nuclear is an option, but it is unlikely to be available quickly enough to serve as replacement generation for retiring power plants.

replacement generation to be available before 2034, AEP must begin spending money now for planning, design, siting, permitting, financing, equipment and fuel procurement, and construction.

35. In addition, prior to building or acquiring replacement generation resources, AEP must begin spending money now for portfolio modelling and other studies so that the appropriate balance between replacement generation, market purchases, financial and fuel hedging, and other arrangements can be developed. This type of portfolio modelling would be a precursor to any definitive steps to obtain replacement generation resources. These costs are not likely to be recovered if the utility petitioners prevail in this litigation.

36. Given that many existing generators are likely to also be forced into retirement before 2034 due to unattainable requirements of the GHG Rule, much new replacement generation will be required across the country, resulting in cost increases and delays for all new generation projects. Planning and execution will need to begin immediately for such replacement generation to be in service before 2034.

PCCC will lead to stranded costs

37. Looking at APCo again, the 2024 ELG Rule will require approximately $340 million in capital investments at three AEP facilities just as we are completing the installation of over $94 million dollars' worth of bioreactor equipment to meet the 2020 ELG Rule requirements. With the 2020 Rule's requirements still binding, EPA has finalized a new Rule that will require AEP to abandon new bioreactor equipment to treat FGD wastewater, as required by the 2020 Rule (which, in some cases, is still being commissioned and optimized) and replace it with the costly and unproven membrane technology that EPA rejected as not yet commercially available in the 2020 ELG Rule. The costs of the abandoned bioreactor equipment, compounded with equally significant added costs to comply with the new Rule, will ultimately be borne by our ratepayers, who are already facing increased utility and energy costs.

38. As mentioned, AEP has invested $94 million between 2020 and 2023 to install bioreactors to comply with the 2020 Rule. Those investments to comply with the 2020 Rule will only be usable until the 2024 Rule's compliance systems (membrane filtration ZLD systems) are placed into service. The bioreactor equipment recently installed for compliance with the 2020 Rule will not be usable in conjunction with the new technology requirements. Rate payers will be expected to continue to pay for them until AEP has recovered its stranded investments, on top of what they will be paying for the 2024 rule's compliance investments. The annual cost of service on the membrane filtration ZLD investments is expected to be $14 million per year beginning in 2024 and $113 million over the first 10 years after they are placed into service, assuming customers will continue to pay for those through 2040.

39. It is almost certain that AEP's investments in the bioreactor equipment for the 2020 Rule would not be fully depreciated upon the decommissioning date of the 2020-required equipment. This would leave significant costs on the companies' books for equipment that would no longer be useful. While AEP could still seek recovery of those investments, there are no guarantees that those requests would be approved by state utility commissions.

A Decision to PCCC has significant Reliability Impacts that harm AEP's reputation and that harm our customers and communities

40. The Regional Transmission Operators that oversee grid reliability in the states AEP operates are already seeing reliability concerns – even without the impacts of the ELG and GHG Rule. The Southwest Power Pool (SPP) recently noted "SPP is not expressing these concerns about a hypothetical resource adequacy scenario in the future. SPP and other grid operators are currently working to develop planning and operations policies and practices to deal with resource adequacy issues that have already manifested."[7] SPP notes its concerns about resource adequacy were identified before the GHG Rule was finalized, and says that it did not consider the additional at-risk generation that may retire and not be adequately replaced as a result of the GHG Rule. "This outcome would further intensify the need for generating capacity and associated transmission upgrades in the SPP region, likely at a pace and cost unprecedented for the industry."[8]

41. The PJM Interconnection (PJM), which covers thirteen states and the District of Columbia, has issued a similar statement, which notes that premature retirements of baseload coal units jeopardize grid reliability, "in the very years when we are projecting significant increases in the demand for electricity,…" and that "EPA has not sufficiently reconciled its compliance dates [under the GHG Rule] with the need for generation to meet dramatically increasing load demands on the system."[9] Those same reliability concerns arising from GHG Rule-related retirements are exacerbated by ELG Rule-related retirements.

42. The North American Electric Reliability Corporation (NERC), is a not-for-profit international regulatory authority whose mission is to assure the effective and efficient reduction of risks to the reliability and security of the grid. NERC develops and enforces Reliability Standards; annually assesses seasonal and long-term reliability; monitors the bulk power system through system awareness; and educates, trains, and certifies industry personnel. NERC is the Electric Reliability Organization (ERO) for North America, subject to oversight by the Federal Energy Regulatory Commission (FERC) and governmental authorities in Canada.

43. In its 2024 Summer Assessment, NERC noted that "[a] large part of North America could be at risk of supply shortfalls during heat waves and extreme summer conditions that can affect generation or wind output or the transmission systems." NERC also noted that Texas, in which AEP provides significant transmission service, is at elevated risk.[10]

44. Reliability constraints are not limited to the summer. In its 2023 Winter Reliability Assessment, NERC found that over the course of the December-February winter period, a large portion of North America was at risk of insufficient electricity supplies during peak periods.[11]

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[7] See SPP Statement on the Recent Greenhouse Gas Emission Rule, available at https://www.spp.org/documents/71677/spp%20statement%20on%20epa%20final%20ghg%20rule%20202405020.pdf.

[8] *Id.*

[9] PJM Statement on the Newly Issued EPA Greenhouse Gas and Related Regulations, available at 20240508-pjm-statement-on-the-newly-issued-epa-greenhouse-gas-and-related-regulations.ashx

[10] NERC, "2024 Summer Reliability Assessment," available at https://www.nerc.com/pa/RAPA/ra/Pages/default.aspx

[11] NERC, "2023 Winter Reliability Assessment," p.5, Report, available at https://www.nerc.com/pa/RAPA/ra/Pages/default.aspx

45. NERC is not alone in its assessment. PJM has also raised concerns about the rapid retirement of dispatchable generation and their fear that the current pace of new generation is not sufficient to keep up with expected retirements.[12] PJM went so far as to say that, "For the first time in recent history, PJM could face decreasing reserve margins should these trends continue."[13]

46. The forced retirement of dispatchable, reliable power plants as a means of compliance with the ELG Rule will only exacerbate these reliability concerns. And as noted, decisions about whether to retire a plant as a means of complying with the ELG Rule must be made within the next 18 months and informed decisions cannot be made while there is so much uncertainty surrounding all of the applicable regulations that will apply to both existing and new, replacement generation.

While Plant Closures May Not Occur for Several Years, Even Prospective Plant Closures Have Impacts on Employees and Communities

47. Coal-fired power plants require highly skilled employees and provide well-paying jobs. The plants also provide sizable tax revenues and stimulate associated employment in other sectors that support both the plant and its employees. Coal-fired power plants and their employees often are significant supporters of the communities where they are located, and when plants are retired and decommissioned, they can leave a significant economic void.

48. The community impacts of compliance with this rule are perhaps most stark for Appalachian Power Company, which operates 3 coal-fired power plants in West Virginia. A recent study found that our Amos Plant, located in Winfield, WV, generates an estimated $320 million in economic activity, $123 million in labor income and supports 1,246 jobs annually in the region. The Mitchell Plant, located in Moundsville, WV, generates $111 million in economic activity, $35 million in labor income and supports nearly 459 jobs annually in the region. Finally, the Mountaineer plant, located in New Haven, WV, generates $98 million in economic activity, $32 million in labor income and supports 414 jobs annually in the region. Combined, these three plants located within just a few hours of each other represent more than half a billion dollars in economic activity for the State of West Virginia, over 2000 jobs, and almost $200 million in labor income. Shutting down the plants prematurely would have a devastating impact on West Virginia and communities in neighboring states, even before other impacts of the rule, such as higher energy costs and reliability concerns, are taken into consideration.

49. If AEP chooses to permanently cease coal combustion as a means of complying with the 2024 ELG Rule, that decision must be made before December 31, 2025. Absent a stay – such a decision would most likely need to be made during the pendency of this litigation. A decision to close a plant will impact our employees and communities, who will need to begin making alternative plans. Employees will face uncertain prospects for employment while the fate of the plant is in limbo during the litigation. Hard questions to be answered include whether they should look for employment elsewhere, including potentially relocating, or risk the chance that the plant will close if the court doesn't vacate the rule. Communities similarly must budget for future years and must consider uncertain scenarios in which they must identify ways to replace the tax revenues generated by the plant if the plant closes.

[12] PJM, Inc., "Energy Transition in PJM: Resource Retirements, Replacements, and Risks (Feb. 24, 2023), p.2, energy-transition-in-pjm-resource-retirements-replacements-and-risks.ashx.
[13] *Id.*

50. Even if a plant closure doesn't materialize, without a stay, the employees and the community will have been harmed by the uncertainty and the planning efforts associated with this uncertainty.

Compliance with the Rule Has Negative Impacts on Our Ratepayers

51. In addition to providing reliable power to customers, we must also continue to ensure it is affordable. AEP, in particular, serves a lower income customer base than most other utilities. In fact, our customers are below the national average for household income in ten of the eleven states in which we provide electric service, and in many of those states, our customers are also below the state average for household income.
52. AEP has 5 coal plants currently scheduled to operate well into the future. Retiring any of those plants ahead of schedule, in order to comply with the ELG rule (and/or the GHG Rule), would force us to recover undepreciated plant balance from ratepayers in several states, including Kentucky, West Virginia and Arkansas – some of the poorest states in the country. Indeed, $460 million has been spent at these plants since 2016 to comply with MATS, ELG and CCR so that these plants could continue operating. Retiring these plants because of the compliance obligations of the ELG Rule, just a few years after mandating installation of costly new controls, is a bitter pill for our regulatory commissions and ratepayers to swallow.
53. If plants are forced to retire prematurely, ratepayers are hit twice: once to pay for the undepreciated balance on any plants forced to retire prematurely and then again, to pay for replacement generation.
54. Whatever compliance alternative is selected, rates for the average customer in our operating companies that own and operate coal plants would be expected to significantly increase.

Conclusion

55. As outlined above, compliance with the ELG Rule during the pendency of this litigation harms AEP in several ways. First, it requires us to commit to spending millions of dollars to install unproven membrane filtration ZLD technology without having sufficient time to properly design and evaluate it for the intended application. It also may require us to spend money to procure replacement generation, if we end up electing to retire coal combustion as the means of compliance with the ELG Rule. Defensible, well-reasoned decisions about the type of replacement generation to be developed are impossible in the current regulatory landscape, where all of these new rules are being litigated and there is no certainty about what requirements will survive and be applicable. None of these costs are completely reversible if utility petitioners prevail in this litigation. Custom designed equipment generally cannot be returned. Dollars spent on labor, consulting, portfolio modeling, generating facility design, planning, permitting, engineering, site selection and acquisition, fuel procurement, financing and other studies and costs cannot be refunded. Legally binding retirement commitments generally cannot be undone.
56. Moreover, these costs cannot be deferred or delayed until the courts reach a final determination on the merits of this litigation. Optimistically, AEP expects the litigation process to take at least 2-3 years. But the Rule's compliance deadlines do not give AEP any time to spare. On the contrary, time is of the essence, unless the Rule is stayed.
57. Additionally, compliance with the rule jeopardizes grid reliability at a time when demand for electricity is growing. Decisions about retirement as a means of compliance with the rule must

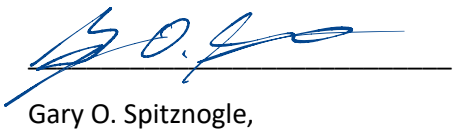
be made during the pendency of this litigation, and require that decisions about replacement generation be made while the requirements of the GHG Rule are also under litigation and make it difficult to determine how much new generation is actually needed. In other words, if the GHG Rule is upheld, multiple new gas turbines will likely be needed, with each operating at only 20% or 40% capacity, whereas if the GHG Rule is overturned, fewer turbines will be necessary to replace generation that is retiring.

58. If the Rule remains in effect while this litigation is pending, AEP will have no choice but to incur significant compliance costs as well as to make decisions about the optimal generation mix to meet future demand without having all of the necessary information – decisions that will jeopardize affordability and reliability and which may lead to reputational as well as financial harms to AEP and our customers.

59. In sum, this Court should stay this rule until the ELG Rule litigation is complete, and if the rule is upheld, until all of the litigation over all of the EPA rules has concluded, so that utilities can make the types of "smart investments" and informed decisions EPA alluded to in its press release as the rationale for the simultaneous release of the new utility rules.

I declare under penalty of perjury under the laws of the United States of America, pursuant to 28 U.S.C. § 1746, that the foregoing is true and correct to the best of my knowledge.

Executed on this 25 day of July, 2024, in Columbus, OH.



Gary O. Spitznogle,
Vice President, Environmental Services
American Electric Power

ATTACHMENT A
TO
DECLARATION OF GARY O. SPITZNOGLE
VICE PRESIDENT, ENVIRONMENTAL SERVICES
AMERICAN ELECTRIC POWER

Attachment A
The Problem with EPA's Technology Premise

The Steam Electric Fleet

- EPA estimates that 141 to 170 steam electric power plants will be subject to and incur compliance costs under the 2024 ELG Rule. 89 Fed. Reg. 40,207
- Steam electric plants provide over 675,000 MW of power to the U.S. grid 24 hours per day, 7 days per week, nearly 365 days per year.
    - *See* www.eia.gov/electricity/monthly/epm_table_grapher.php?t=epmt_1_01.
- Nationally, steam electric (coal-fired) plants provide over 16% of total electric power generation.
    - *See* www.eia.gov/tools/faqs/faq.php?id=427&t=3.
- Regionally in the Midwest and South, and in relation to national baseload generation, these plants provide even higher percentages of total generation.
    - In States within the Eighth Circuit, steam electric (coal-fired) plants represented, as a percentage of total power generation in 2021: 74% in Missouri, 57% in North Dakota, 49% in Nebraska, 36% in Arkansas, 34% in Iowa, 27% in Minnesota, and 9% in South Dakota.
    - *See* www.nei.org/resources/statistics/state-electricity-generation-fuel-shares.

Continuous Operation of the Fleet is Critical to the Grid

- Most plants subject to the 2024 Rule provide baseload power to the grid, which is the minimum electricity required to be provided at a steady rate over a period of time for the grid to operate and meet electric demand.
    - They must operate continuously, reliably and cost-effectively to ensure the grid has sufficient power to meet basic electricity demands, and that ratepayers receive dependable and affordable electricity.
    - Required maintenance and repairs at these plants is carefully orchestrated to minimize disruption of baseload power generation and ensure backup sources are available during those periods.
- Baseload power is critical to protecting human lives and livelihoods; it is relied upon by hospitals, schools, military and other government facilities, transportation and communication infrastructure, homes, businesses, etc.

Steam Electric Plants Depend on a Continuous Intake and Discharge of High Flows and Volumes of Water

- Coal-fired plants continuously draw in and discharge high volumes of water for cooling and to transport ash and other byproducts produced by burning coal to generate electricity. *See* Comments of the Utility Water Act Group (UWAG) on EPA's Proposed Rule for the Supplemental Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category at 7, n. 10 (May 30, 2023) ("UWAG Comments").

    - The amount of water at a plant must be balanced in order to ensure the plant has sufficient water to meet its needs, but not so much that it becomes flooded or has uncontrolled releases of wastewater. *See*, *e.g.*, UWAG Comments at 138.
- Maintaining the rate and volume of water flow, including discharges of wastewater, is critical to the reliable continuous operation of baseload coal-fired power plants.

Wastewater Treatment Systems Must Be Able to Meet Pollutant Limits at High Volume, High Flow Rates

- Systems designed to treat wastewater at baseload steam electric power plants must not only be effective at removing pollutants to the degree required to meet permit limits, but also capable of continuously and reliably doing so at the required flow rate of those plants.
- Systems that have proven capable of providing such treatment at steam electric plants include:
    - settling ponds (where pollutants are removed from wastewater by settlement, often in combination with chemical and biological treatment)
    - equipment that physically removes pollutants from wastewater (such as with screens) combined with chemical and biological treatment to aid that removal.

EPA's Technology Premise Rests on Membranes and Evaporators

- EPA states that membrane filtration, spray dryer evaporation, and thermal evaporation "alone or in any combination" is the "technology basis" for the 2024 Rule's zero discharge limits applicable to flue gas desulfurization (FGD) wastewater and combustion residual leachate (CRL). 89 Fed. Reg. 40,215, 225.
    - EPA acknowledges in 2024 Rule preamble that it "rejected membrane filtration" as a standalone best available technology in the 2020 Rule "due in part to the lack of a single full-scale domestic installation, which is still the case today", but explains the 2020 Rule "did not evaluate a technology basis that includes the three zero-discharge technologies that form this final rule's BAT basis."

Membranes and Evaporators Are Not Well Suited to Full Scale Use at Steam Electric Plants

- Systems that use membranes or evaporators, or both, have been used to separate pollutants or impurities from water for various purposes for decades.
    - The basic technology used by membranes and evaporators is not especially modern or novel; membranes are used in home reverse osmosis systems to treat drinking water, and evaporator technology is used in home clothes dryers, hair dryers, and food dehydrators.
    - Membrane and evaporator technology has been used by various industrial processes, typically where maintaining high volume, high flow rates of complex wastestreams is not critical.

  - Membrane and evaporator technology can be employed at steam electric plants to treat certain wastestreams, such as use of membranes for low flow wastestreams or evaporators in hot, dry climates.
- Membrane and evaporator technology is not well suited for treating most high volume, high flow wastestreams, particularly where that wastewater has complex or significant pollutant loads. *See* UWAG Comments at 65-66.
  - Membranes and evaporators generally are slow at removing pollutants in most circumstances; as a result, an exceptionally large amount of membrane and/or evaporator equipment is required in order to attempt to keep up with high volume, high flow, complex wastestreams of a steam electric power plant at full operational scale.
  - Membranes and evaporators are prone to fouling, and as a result steam electric wastewater requires unique and often extensive pretreatment measures (e.g., introduction of chemicals) before the wastewater enters membrane or evaporator equipment. *See* UWAG Comments at 7, n.10.
    - The need for pretreatment adds to the amount of equipment and extent of systems needed, and of equipment failure risks and the chemical complexity of the wastewater being treated.
    - Based on the risk of membranes and evaporators to foul and go offline, as a general matter a plant will require at a minimum of 50% additional (redundant) equipment for use as backup to ensure compliance. *See* Electric Power Research Institute (EPRI) Comments on EPA's Proposed Rule for the Supplemental Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category at 39 (May 26, 2023) ("EPRI Comments").
  - Membranes and evaporators produce brine or waste byproducts that must be handled and treated at a site, such as by combining with fly ash to allow landfill disposal, further adding to total system complexity. UWAG Comments at 67.
    - Many facilities do not produce sufficient amounts of fly ash to allow landfill disposal of brine or waste byproducts produced by these systems, further limiting potential use of these systems. UWAG Comments at 72-77.
  - The more equipment necessary for a given task, the more points of potential failure are introduced into the system, potentially negating its ability to provide continuous, reliable performance.

Membrane and Evaporator Equipment May Not be Attainable in Time Due to Supply Chain and Financing Risks

- Supply chain limits present risks in obtaining necessary equipment in time to attempt to meet 2024 Rule limits. UWAG Comments at 92-93.
  - For example, demand is increasing for polymeric membranes to provide separation processes in food and beverage, pharmaceutical, oil and gas, lithium ion battery production (e.g., for electric vehicle batteries).
- Acquiring and installing membrane and separate equipment will result in billions of dollars of costs to the fleet (likely over $100 million in costs for many facilities), *see*

UWAG Comments at 15-18, 44, and as a result facilities will be required to obtain financing to pay for the acquisition, installation and operation of the equipment

- Regulated facilities would need to receive State approval to recover costs from customers through increased electricity rates, and there is no guarantee States would approve such recovery in light of concerns over affordability of electricity (particularly in light of costs imposed on customers for equipment to comply with the 2020 Rule, which the 2024 Rule is now quickly rendering obsolete well ahead of normal amortization schedules). *See* UWAG Comments at 16.
- Market facilities would need to obtain financing at current rates, and lenders may be skeptical about providing such financing in light of the rapid changes in requirements imposed on facilities that render capital investments (e.g., in compliance with the 2020 Rule) prematurely obsolete.

Achieving Zero Discharge Limits Via Membranes and Evaporators is Highly Uncertain

- Installing membrane and evaporator technology, even if all necessary equipment can be acquired and installed within a facility and operated continuously and reliably, is not guaranteed to perform at a zero discharge level.
  - There is a risk that, once installed, the equipment will not achieve 100% removal of one or more pollutants on continuous, uninterrupted basis.
  - Examples of potential circumstances that could cause performance failure include failure within any one of the many points of failure in the complex systems that would be required, such as pretreatment system failures, extensive fouling of membranes or evaporators preventing continuous full-scale operation, or failure by the system to remove all pollutants within the wastestream.
  - Equipment vendors are unlikely to fully guarantee continuous zero discharge performance.
- The design of a treatment system on a baseload coal plant that uses membranes and/or evaporators to reliably achieve zero discharge at required flow volumes and rates will be inherently complex and uncertain, including:
  - a determination of all equipment, processes and facility components that would be required (e.g., pretreatment systems, membranes and/or evaporators, brine transport and handling) that accounts for flow rates, flow volumes, wastewater chemistry, etc.
  - a determination of the space that would be required for all equipment and components, and potential plant locations that would provide that space
  - a determination of required testing, maintenance, repair schedules, and operating parameters
  - a determination of whether the necessary equipment is available within supply chains, and whether the equipment can be financed, acquired, installed, tested and operated within the deadlines set by the Rule
  - a determination whether the complete system can reliably operate on a continuous 24/7/365 basis
  - a determination whether the complete system can reliably achieve zero discharge on a continuous basis

- For all of these reasons, many if not most steam electric power plants in the U.S. face serious questions -- and genuine doubts -- whether membrane and evaporator technology is available for the use and performance required at those plants to achieve the performance required by the Rule within the deadlines set by the Rule.

The Problems with EPA's Technical Premise are Reflected in Its Tremendous Underestimate of Costs

- For similar reasons, even if membrane and evaporator technology is ultimately shown to be available to a facility to meet the limits and deadlines set by the 2024 Rule, the actual cost of installing and operating membranes and/or evaporators to meet the limits of the 2024 Rule will be much higher than EPA estimated. *See* UWAG Comments at 80-87.
- Specifically, EPA's cost estimates for the 2020 Rule relied on a model that tremendously underestimated actual costs experience by industry to comply with the 2020 Rule, and in the 2024 Rule EPA applied the same model to estimate costs without adjusting for errors in its 2020 Rule estimates. *Id.*

Many of these Costs Are Starting to be Incurred Now

- Companies cannot wait, they need to start planning for compliance now.
  - Many facilities probably cannot retire given the realities of grid requirements, and deciding to retire would take processes that are many months long and uncertain.
  - Accordingly, and in light of the Rule's deadlines, companies need to start (and likely most have already started) to invest money and time to, among other things: evaluate potential membrane, evaporator, pretreatment, and brine handling equipment and systems; consider potential plant upgrades (including retrofits of retrofits already made in reliance on the 2020 ELG Rule); design plant upgrades; attempt to secure financing; order equipment in time to attempt to avoid supply chain problems; and arrange for installation and testing of systems.

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EXHIBIT 2

United States Environmental Protection Agency | Office of Water Washington, DC 20460 | EPA-821-R-20-001 August 2020



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

United States
Environmental Protection
Agency

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

EPA-821-R-20-001

August 2020

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

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SECTION 4
TREATMENT TECHNOLOGIES AND WASTEWATER MANAGEMENT PRACTICES

This section provides an overview of treatment technologies and wastewater management practices at steam electric power plants for flue gas desulfurization (FGD) wastewater and bottom ash (BA) transport water. All technologies evaluated as part of the 2015 rule are still being used in the industry; see the 2015 TDD for a full description of these technologies. This section focuses primarily on technologies identified for the treatment of FGD wastewater and BA transport water since the 2015 rule.

4.1 FGD Wastewater Treatment Technologies

In promulgating the 2015 rule, EPA identified surface impoundments as the most prevalent treatment technology for plants discharging FGD wastewater, and chemical precipitation (i.e., tank-based systems designed primarily to remove suspended solids) as the second most common treatment technology. These technologies are described in the 2015 TDD. While approximately half of the industry discharging FGD wastewater still relies on these technologies, with the most prevalent now being chemical precipitation, more advanced treatment technologies have become more common since the 2015 rule. Several plants have upgraded their FGD wastewater treatment by installing either biological or thermal treatment systems. The biological systems installed have been either the high residence time anoxic/anaerobic biological technology—used as the basis for the FGD BAT (best available technology economically achievable) limitations in the 2015 rule— or a similar process that targets removal of the same pollutants in a smaller system with a shorter hydraulic residence time in the bioreactor. Thermal systems installed have been either a spray dryer evaporator, an adiabatic evaporator, or the falling-film evaporator design, which was used as the basis for the NSPS limitations and the BAT Voluntary Incentive Program (VIP) in the 2015 rule. See the 2015 TDD for a description of thermal treatment technologies and other zero discharge technologies.

EPA also identified several additional treatment technologies that were developed (or adapted from other industry sectors) in recent years and have been tested at some domestic power plants or had been tested or installed at foreign power plants. This section provides a summary of the treatment technologies evaluated as part of the final rule, including:

- Biological treatment.
- Zero-valent iron (ZVI).
- Membrane filtration.
- Thermal treatment.
- Encapsulation.
- Other pilot-scale-tested technologies.

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4.1.1 Biological Treatment

Several types of biological treatment systems are currently used to treat FGD wastewater. These biological technologies include:

- Anoxic/anaerobic biological treatment systems, designed to remove selenium and other pollutants.
- Sequencing batch reactors, which alternate between aerobic and anaerobic stages to remove nitrates and ammonia.
- Aerobic bioreactors for reducing biological oxygen demand (BOD).

These biological treatment processes are typically operated downstream of a chemical precipitation system or a solids removal system (e.g., clarifier or surface impoundment).

The anoxic/anaerobic biological technology is designed to remove selenium, nitrate-nitrite, mercury and other pollutants. This process uses an anoxic/anaerobic fixed-film bioreactor that consists of an activated carbon bed or other permanent porous substrate that is inoculated with naturally occurring, beneficial microorganisms. The microorganisms grow within the substrate, creating a fixed film that retains the microorganisms and precipitated solids within the bioreactor. The system uses microorganisms chosen specifically for use in FGD systems because of their hardiness in the extreme water chemistry, as well as selenium respiration and reduction.

The microorganisms reduce the selenate and selenite to elemental selenium, which forms nanospheres that adhere to the cell walls of the microorganisms. The microorganisms can also reduce other metals, including arsenic, cadmium, nickel, and mercury, by forming metal sulfides within the system (Pickett, 2006).

High Residence Time Reduction Biological Treatment

High residence time reduction (HRTR) biological treatment systems consist of chemical precipitation followed by an anoxic/anaerobic fixed-film bioreactor. This technology, as it has been applied at plants for treating FGD wastewater, uses equipment that is large enough to provide for hydraulic residence times in the bioreactor that are typically on the order of 10 to 16 hours. Plants usually employ multiple bioreactors to provide the necessary residence time to achieve the specified removals. The HRTR biological technology was the basis for effluent limitations established by the 2015 rule.

The bioreactor is designed for plug flow to ensure that the feed water is evenly distributed and has maximum contact with the microorganisms in the fixed film. As wastewater passes through the bioreactor, it goes through zones operating at differing oxidation-reduction potential (ORP). Plants operate the bioreactors to achieve a negative ORP, which provides the optimal environment to reduce selenium to its elemental form. The top part of the bioreactor, where the plant feeds the wastewater, is aerobic with a positive ORP, which allows nitrification and organic carbon oxidation to occur. As the wastewater moves down through the bioreactor, it enters an anoxic zone (negative ORP) where denitrification and chemical reduction of selenium (both selenate and selenite) occur (Pickett, 2006; Sonstegard, 2010).

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The HRTR biological technology is described in detail in Section 7.1.3 of the 2015 TDD. EPA identified at least five plants that have operated this system at full-scale in the steam electric power generating industry. One of these plants no longer operates HRTR and has installed an evaporation system. Several other plants have conducted pilot tests of this technology in preparation for making upgrades to comply with the 2015 rule requirements.

Low Residence Time Reduction Biological Treatment

In the years since EPA first identified the HRTR biological technology during the development of the 2015 rule, power companies and technology vendors have worked to develop processes that target removals of the same pollutants in a smaller system with a lower hydraulic residence time in the bioreactor. These technologies, described here as low residence time reduction (LRTR) technologies, use similar treatment mechanisms (e.g., anoxic/anaerobic fixed-film bioreactors) to remove selenium, nitrate, nitrite, and other pollutants in less time, typically on the order of 1 to 4 hours hydraulic residence in the bioreactor.

One LRTR technology includes a chemical precipitation pretreatment system followed by an anoxic, upflow bioreactor followed by a second stage downflow biofilter. The shorter hydraulic residence time of this system allows for use of smaller bioreactors and other equipment, resulting in a treatment system that is physically much smaller than the HRTR system. Data provided by the power industry and an independent research organization show that the LRTR system performance is comparable to that achieved by HRTR technology. Much of the LRTR bioreactor and related equipment is fabricated off-site as modular components. Modular, prefabricated, skid-mounted components, coupled with the smaller physical size of the system, results in lower installation costs and shorter installation times, relative to HRTR systems, which are usually constructed on-site. At least four plants have installed full-scale LRTR systems currently being used to treat FGD wastewater and this technology has been pilot tested using FGD wastewater at more than a dozen steam electric power plants since 2012.

Another LRTR technology, fluidized bed reactors (FBRs), has historically been used to treat selenium in mining wastewaters; however, it is now being tested on FGD wastewater. The FBR system is also an anoxic/anaerobic fixed-film bioreactor design. It relies on an attached growth process, in which microbial growth forms on granular activated carbon media that is fluidized by an upflow of FGD wastewater through the suspended carbon media. EPA identified 12 pilot studies of the FBR technology for selenium removal in mining, refining/petrochemical, and steam electric industries. Three of these pilot studies involved FGD wastewater.

4.1.2 Zero Valent Iron

ZVI, in combination with other systems such as chemical and physical treatment, can be used to target specific inorganics, including selenium, arsenic, nitrate, and mercury in FGD wastewater.

The technology entails mixing influent wastewater with ZVI (iron in its elemental form), which reacts with oxyanions, metal cations, and some organic molecules in wastewater. ZVI causes a reduction reaction of these pollutants, after which the pollutants are immobilized through surface adsorption onto iron oxide coated on the ZVI or generated from oxidation of elemental iron. The coated, or spent, ZVI, is separated from the wastewater with a clarifier. Spent ZVI can be

disposed of in a non-hazardous landfill. The quantity of ZVI required and number of reaction vessels can be varied based on the composition and amount of wastewater being treated.

Treatment configurations for FGD wastewater would typically include chemical precipitation followed by ZVI treatment and may also include pretreatment to partially reduce influent nitrate concentrations at plants with high nitrate levels in the FGD purge.[14] The purpose of the nitrate pretreatment is to reduce the consumption rate of the ZVI media, which reacts with both the nitrates and selenium in the wastewater. A potential application for FGD wastewater would employ four reactors in series. This configuration provides extra treatment capacity that allows the operator to bypass and isolate individual units whenever maintenance is needed without having to shut down the entire treatment system. This configuration, by including an extra ZVI reactor in the treatment train, also provides additional polishing treatment capability that can be appealing for some plants.

EPA identified two full-scale installations of the ZVI technology for selenium removal in mining wastewater and seven completed pilot-scale studies of ZVI used for FGD wastewater treatment.[15, 16] At least four additional pilot-scale studies for FGD wastewater treatment were in the planning stage at plants in the eastern United States, as of 2016. The data in the record from a subset of these pilot tests indicate that the combination of chemical precipitation and ZVI technology, along with nitrate pretreatment where warranted, can produce effluent quality comparable to chemical precipitation followed by low residence time reduction (CP+LRTR), and chemical precipitation followed by high residence time reduction (CP+HRTR) technologies.

4.1.3 Membrane Filtration

These systems are specifically designed to treat high TDS and TSS wastestreams using thin semi-permeable filters or film membranes. Membrane filtration is a treatment process used for the removal of dissolved materials from industrial wastewater and includes microfiltration, ultrafiltration, nanofiltration, forward osmosis, and reverse osmosis (RO) membrane systems. The size of the particle that can pass through the membrane is determined by the membrane pore size, with RO membranes being the most restrictive and microfiltration being the least restrictive. Most membrane filtration systems use pumps to apply pressure to the solution from one side of the semi-permeable membrane to force wastewater through the membrane, leaving

[14] FGD purge with nitrate/nitrite concentrations at or above 100 mg/L typically require additional denitrification before ZVI treatment.

[15] EPA has limited data on the performance and configuration of the two full-scale ZVI systems treating mining wastewater (Butler, 2010). At least one of the systems includes ZVI in combination with a reverse osmosis membrane system to target selenium removal.

[16] In addition to the seven FGD pilots of ZVI, EPA has also observed ZVI technology in treating ash transport water during impoundment dewatering at a plant. In this application, the impoundment water was first treated by reverse osmosis membrane filtration, and the membrane reject stream was sent to ZVI reactors for treatment. The membrane permeate and ZVI effluent streams were both discharged by the plant to surface waters. Although this application was not treating FGD wastewater, many of the pollutants present in FGD wastewater are also present in ash impoundments, and these pollutants were effectively removed by the ZVI process (ERG, 2019). A similar treatment train has been suggested for FGD wastewater: chemical precipitation followed by reverse osmosis membrane filtration, with the membrane reject stream sent to a ZVI stage consisting of three reactors in series. Similar to the treatment system for the impoundment, the RO permeate and ZVI effluent would be discharged (unless the RO permeate was reused within the plant).

behind dissolved solids retained ("rejected") by the membrane and a portion of the water. The rate that water passes through the membrane depends on the operating pressure, concentration of dissolved materials, and temperature, as well as the permeability of the membrane.

Forward osmosis (FO) uses a semi-permeable membrane and differences in osmotic pressures to achieve separation. These FO systems use a draw solution at a higher concentration than the feed, (e.g., FGD wastewater) to induce a net flow of water through the membrane. This results in diluting the draw solution and concentrating the feed stream. This technology is different from RO, which utilizes hydraulic pressure to drive separation. FO technology is typically better suited for high-fouling streams than traditional RO because external pumps are not needed to drive treatment.

Membrane systems separate feed wastewater into two product streams: a permeate stream, which is the "clean" water that has passed through the membrane, and the concentrate stream, which is the water (or brine) rejected by the membrane. The percentage of membrane system feed that emerges from the system as permeate is known as the water recovery. Depending on wastewater characteristics, membrane systems may require pretreatment to remove excess TSS and organics to prevent scaling and fouling in industrial applications. Fouling occurs when either dissolved or suspended solids deposit onto a membrane surface or a microbial biofilm grows on the membrane surface and degrades its overall performance.

As part of the reconsideration of the 2015 rule, the Agency identified and further reviewed several new uses of membrane filtration technologies currently being studied in the industry. Depending on the FGD wastewater characteristics, these membrane systems typically include nanofiltration membranes, RO, or FO. To reduce fouling, membrane filtration systems have been designed with vortex generating blades or vibratory movement. Other technologies focus on a microfiltration pretreatment step that targets scale-forming ions where FGD wastewater characteristics indicate potential fouling.

Incorporating membranes into existing chemical precipitation systems can improve the efficiency of the membrane system and may help lower the capital and operation and maintenance costs. Many of the systems piloted for FGD wastewater to date have included some type of pretreatment to reduce TSS before entering the membrane system (e.g., surface impoundment, chemical precipitation, microfiltration). Membrane systems can also be configured with a post-processing RO system to further remove pollutants from the permeate. Additionally, membrane systems can be used in combination with other technologies (e.g., thermal evaporation) to treat FGD wastewater or achieve zero discharge.

Permeate streams from these systems can be reused within the plant or discharged, while reject streams (i.e., concentrated brine) would be disposed of in a landfill using encapsulation (See Section 4.1.5), in a commercial injection well, or another process, such as thermal system treatment (see Section 4.1.4).

EPA identified two full-scale domestic installations of reverse osmosis and one in South Africa for selenium or nitrate removal in the mining industry, and five domestic pilot studies in the petroleum refining and agriculture industries. EPA further identified four full-scale installations of membrane filtration in the coal-to-chemical industry in China and the textile industry in

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India.[17] In the steam electric industry, EPA identified 17 pilot-scale studies of nanofiltration and reverse osmosis used for FGD wastewater treatment world-wide (ERG, 2020af) and 12 full-scale installations in China, South Korea, and Finland (ERG, 2020aa; Beijing Jingneng Power, 2017; Nanostone, 2019; Lenntech, 2020; and Broglio, 2019).[18] Some of the full-scale systems employ pretreatment and a combination of RO and forward osmosis. Others operate pretreatment followed by nanofiltration and RO. At least one plant uses thermal treatment to produce a crystallized salt from the brine which is sold for industrial use. EPA is also aware of one U.S. facility that is conducting a long-term pilot to test a membrane filtration system for the treatment of FGD wastewater (ERG, 2020x). Data from this pilot are not available.

4.1.4 Thermal Treatment

Thermal technologies include a variety of treatment technologies that use heat to evaporate water and concentrate solids and other contaminants. Some of these systems can be operated to achieve full evaporation of all liquid, resulting in only a solid product, or achieve partial evaporation of liquid. These thermal technologies can also be used in combination with other technologies to treat FGD wastewater or achieve zero discharge.

One type of thermal treatment uses brine concentrators followed by crystallizers, which generates a distillate stream and solid byproduct that can be disposed of in a landfill. As described in the 2015 TDD, three U.S. plants have installed brine concentrator systems for FGD treatment and at least four coal-fired power plants in Italy also operate this type of system for FGD wastewater. Since proposal, EPA has identified one additional full-scale installation of thermal treatment for FGD wastewater at a U.S. plant (ERG, 2020d). As described in Section 4.1.3, in addition to full-scale thermal treatment alone, EPA identified coal-fired steam electric power plants in China that have installed brine concentrators followed by crystallizers following membrane filtration to treat FGD wastewater. This treatment configuration was evaluated as part of the 2015 rule (see Section 7.1.4 of the 2015 TDD for a detailed description of this treatment configuration). As part of this final rule development, EPA identified several additional thermal technologies that rely on this same premise, i.e., using heat to evaporate water and concentrate contaminants.

Spray dryers are an example of a technology that is being applied to FGD wastewater treatment. These systems utilize a hot gas stream to quickly evaporate liquid resulting in a dry solid or powder. For FGD applications, a slipstream of hot flue gas from upstream of the air heater can be used to evaporate FGD wastewater in a vessel. The FGD solids are carried along with the flue gas slipstream, which is recombined with the main flue gas stream. All solids are then removed with the fly ash by the main particulate control equipment (e.g., electrostatic precipitator or fabric filter) and disposed of in a landfill. In cases where fly ash is marketable, and contamination is a concern, a separate particulate control system can be operated on the flue gas

[17] EPA has limited data on the performance and configuration of the two full-scale membrane systems treating mining wastewater and the pilot-scale systems in other industries (Wolkersdorfer, 2015; U.S. EPA, 2014; CH2M Hill, 2010; ERG, 2020aa; ERG, 2019c). These systems may include a variety of membrane systems including nanofiltration, microfiltration, and RO systems.

[18] EPA has limited details on these full-scale membrane systems. Some references include only plant name or location. For this reason, some references may be describing the same installation, and EPA does not have enough information to determine where this may be the case.

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slipstream to capture FGD solids alone. While these spray dryer systems can be an efficient treatment of FGD wastewater, retrofitting these systems into existing plants could be difficult.

One vendor has developed a proprietary technology that combines concepts of the brine concentrator and spray dryer to achieve zero discharge without a crystallizer. The system, referred to as an adiabatic evaporator technology, injects wastewater into a hot feed gas stream to form water vapor and concentrated wastewater. The air-water mixture is separated in an entrainment separator. Water vapor is exhausted, and wastewater is sent to a solid-liquid separator. The concentrated wastewater is recycled and sent back through the system while the solids can be landfilled. An alternative configuration would be to not recycle the concentrated wastewater and instead reject it from the system. This reject stream could be encapsulated, by mixing with fly ash, and landfilled. Pretreatment of FGD wastewater is not required but, for situations where TSS exceeds 5 percent it maybe be cost-effective to operate a clarifier upstream of the evaporator to decrease solids. This system was operated at full-scale at a coal-fired steam electric power plant for three years. FGD wastewater was pretreated using a clarifier, then sent to the adiabatic evaporator where 100 percent of the FGD wastewater was evaporated and solids deposited in a landfill. Because propane was used as the heat source, operation and maintenance costs proved to be too costly, and the system was replaced.

Another vendor has developed a modular brine concentration technology. This system uses thermal energy to heat FGD wastewater and facilitate evaporation. As the wastewater boils, steam is collected, compressed, and directed into proprietary technology that allows the heat to transfer from the steam to the concentrated wastewater stream; causing it to become superheated. As water evaporates from the superheated wastewater, the steam is collected and condensed. This distillate stream can be reused in the plant as cooling tower make up or within the FGD scrubber. The concentrated wastewater, referred to as brine, is discharged from the system once it reaches a set TDS concentration (not to exceed 200,000 parts per million (ppm)). This brine stream is treated through hydrocyclones to remove suspended solids. The resulting liquid can be solidified and landfilled. Pretreatment of FGD wastewater is only required when TSS concentrations exceed 30 ppm. Chemicals are added to maintain pH and inhibit crystal and scale formation. This technology has been pilot tested at four coal-fired power plants in 2015 and 2017.

4.1.5 Encapsulation

Encapsulation is another technology option that may prevent FGD wastewater discharge. Encapsulation is the process by which temperature and chemical reactions are used to bond materials together. This process can also be referred to as fixation or solidification. This technology has been used by plants operating inhibited oxidation scrubber systems, where byproducts from the scrubber are mixed with fly ash and lime to produce a non-hazardous landfillable material. This same approach is being tested with pretreated FGD wastewater by mixing concentrated FGD wastewater, from membrane systems or thermal systems that only achieve partial evaporation. The concentrated FGD wastewater is mixed with various combinations of fly ash, hydrated lime, sand, and/or Portland cement to encapsulate contaminants. Tests of these materials have confirmed that the solids generated meet solid waste leaching requirements (toxicity characteristic leaching procedure (TCLP), and other local landfill regulations (Pastore and Martin, 2017; Martin, 2019).

4.1.6 Other Technologies Under Investigation

EPA also identified several emerging technologies for FGD wastewater treatment. EPA reviewed EPRI reports, industry sources, and published research articles describing alternative FGD wastewater treatment technologies being evaluated to date and identified several that are in the early stages of development. While the technologies described in this section have not been implemented at full-scale levels in the steam electric power generating industry to date, these technologies have been evaluated in pilot-scale testing for FGD wastewater at power plants.

Electrodialysis Reversal and Reverse Osmosis Technology

Electrodialysis reversal (EDR) is a technology that uses an electric current to migrate dissolved ions through stacks of alternating cationic and anionic ion exchange membranes. While this process is typically used to desalinate water, it is now being used to treat FGD wastewater in pilot-scale tests. The EDR technology results in three wastestreams, one permeate stream and two wastestreams. The permeate stream can be further treated with a RO system to remove additional metals and conventional pollutants. Reject from the RO is recycled through the EDR process while the RO permeate can be reused as cooling tower make up or within the FGD scrubber. The two wastestreams, one a calcium chloride rich brine stream and one a sodium sulfate rich brine stream, can be recombined to produce gypsum ($CaSO_4$), solidified, or treated using a crystallizer. This system has been bench-scale tested using FGD wastewater in 2017 and pilot-scale tested for 60 days in the spring of 2018 (ERG, 2020ab).

Closed-Loop Mechanical Vapor Recompression

Mechanical vapor compression is a technology that can be used to treat FGD wastewater, as well as other wastestreams, and was evaluated as a technology option under the 2015 rule. A vendor has come up with a proprietary application of this technology that operates as a closed-loop system. The system uses four interconnecting loops to pre-heat process wastewater, concentrate and crystalize wastewater using turbulent flow heat exchangers, and recover and condense steam to produce a clean distillate stream. This technology is currently used in full-scale operations in metal working and manufacturing applications. EPRI and the technology vendor operated a pilot test of the system to treat FGD wastewater from power plants at the Plant Bowen Water Research Center in 2015 (EPRI, 2015).

Distillation-Based Thermal Transfer System

One vendor has developed a proprietary combination of technologies that operate as one thermally-balanced system to treat industrial wastewater streams. This technology combines degassing, distillation, and demisting to heat industrial wastewater streams, generating a clean water stream and gray water or brine stream. The gray water or brine stream is a concentrated wastewater stream that either flash crystallizes upon discharge or crystallizes upon cooling, resulting in zero liquid discharge. Energy required to drive degassing and distillation can come from steam, natural gas, flue gas, waste heat, or other renewable sources such as solar or geothermal, depending on availability. The vendor has conducted bench scale testing using FGD wastewater and is currently pursuing pilot testing opportunities with industry trade groups and

individual plants. This technology has also been tested on produced water from the oil and gas industry and cooling tower blowdown.

4.2 Bottom Ash Handling Systems and Transport Water Management and Treatment Technologies

As part of this reconsideration, EPA reviewed bottom ash handling systems designed to minimize or eliminate the discharge of BA transport water that are operated by coal-fired steam electric power plants or marketed by bottom ash handling vendors. As part of the 2015 rule, EPA determined that almost 60 percent of the coal-fired power plants in the industry operate wet-sluicing systems on one or more of their coal-fired EGUs. As described in Section 3, many plants have installed, or are installing, bottom ash handling systems that minimize or eliminate the discharge of BA transport water. Specifically, EPA now estimates that just 22 percent of coal-fired steam electric power plants in the industry (projected to be operating beyond 2028) operate wet sluicing systems (see the 2015 TDD for more details on wet sluicing systems). The bottom ash handling technologies evaluated by EPA are listed below:

- Mechanical Drag System.
- Remote Mechanical Drag System.
- Dry Mechanical Conveyor.
- Dry Vacuum or Pressure System.
- Compact Submerged Conveyor.

4.2.1 Mechanical Drag System

A mechanical drag system collects bottom ash from the bottom of the EGU through a transition chute and sends it into a water-filled trough. The water bath in the trough quenches the hot bottom ash as it falls from the EGU and seals the EGU gases. The drag system uses a parallel pair of chains attached by crossbars at regular intervals. In a continuous loop, the chains move along the bottom of the water bath, dragging the bottom ash toward the far end of the bath. The chains then move up an incline, dewatering the bottom ash by gravity and draining the water back to the trough. Because the bottom ash falls directly into the water bath from the bottom of the EGU and the drag chain moves constantly on a loop, bottom ash removal is continuous. The dewatered bottom ash is often conveyed to a nearby collection area, such as a small bunker outside the EGU building, from which it is loaded onto trucks and either sold or transported to a landfill. See Section 7.3.3 of the 2015 TDD for more specific system details.

The mechanical drag system does generate some wastewater (i.e., residual water that collects in the storage area as the bottom ash continues to dewater). This wastewater is either recycled back to the quench water bath or directed to the low volume waste system. This wastewater is not BA transport water because the transport mechanism is the drag chain, not the water (see 40 CFR 423.11(p)).[19]

[19] The mechanical drag system does not need to operate as a closed-loop system because it does not use water as the transport mechanism to remove the bottom ash from the boiler; the conveyor is the transport mechanism. Therefore,

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5.2 FGD WASTEWATER

EPA developed methodologies to estimate costs to install and operate the following technologies: chemical precipitation, CP+LRTR, CP+HRTR, membrane filtration, and thermal treatment.[22] Chemical precipitation is included as pretreatment for more advanced treatment technologies including LRTR, HRTR, membrane filtration, and thermal treatment, and as stand-alone treatment for some subcategories. EPA also estimated the cost savings associated with plants ceasing operation of impoundments currently used to treat FGD wastewater.

For chemical precipitation (Section 5.2.2), EPA included costs to install and operate the following:

- Treatment equipment (equalization and storage tanks, pumps, reaction tanks, solids-contact clarifier, and gravity sand filter).
- Chemical feed systems for lime, organosulfide, ferric chloride, and polymers.
- Solids-contact clarifier to remove suspended solids.
- Pollutant monitoring and analysis.
- Solids handling (sludge holding tank and filter press).
- Transportation and disposal of solids in a landfill.

For CP+LRTR (Section 5.2.3), EPA included all the costs described above for the chemical precipitation system and included costs for the following:

- Treatment equipment (anoxic/anaerobic bioreactor, flow control, backwash supply, storage tanks).
- Chemical feed system for nutrients.
- Pretreatment system (for plants with nitrate/nitrite concentrations greater than 50 parts per million (ppm)).
- Heat exchanger.
- Ultrafilter.
- Pollutant monitoring and analysis.
- Transportation and disposal of solids in a landfill.

For CP+HRTR (Section 5.2.4), the same technology basis as the 2015 rule BAT, EPA included all the costs described above for the chemical precipitation system, and included costs for the following:

- Treatment equipment (anoxic/anaerobic biological treatment system, storage tanks, and backwash system).
- Chemical feed system for nutrients.

[22] EPA estimated compliance costs for thermal treatment; however, EPA did not use that estimate as a basis for an FGD technology option for the final rule. See the "Flue Gas Desulfurization Thermal Evaporation Cost Methodology" for more information (ERG, 2020ae).

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- Pretreatment system (for plants with nitrate/nitrite concentrations greater than 100 ppm).
- Heat exchanger (for plants in certain geographic locations).
- Pollutant monitoring and analysis.
- Transportation and disposal of solids in a landfill.

For membrane filtration (Section 5.2.5), EPA included all the costs described above for the chemical precipitation system (as pretreatment) and included costs for the following:

- Treatment equipment (membrane filtration, reverse osmosis, and storage tanks).
- Concentrate management.
- Transportation and disposal of solids or concentrate.[23]

Section 5.2.1 describes the cost inputs and the process for updating the FGD wastewater flow rates from the 2015 rule, Section 5.2.2 through Section 5.2.5 describe the cost methodologies for each of the technology options, and Section 5.2.6 describes the impoundment operation cost savings methodology.

5.2.1 FGD Cost Calculation Inputs

To calculate plant-level engineering costs associated with implementing FGD wastewater treatment technologies, EPA developed a cost calculation database containing a set of input values and a set of equations that define relationships between costs and FGD wastewater flow rates (ERG, 2020g). To establish the input values, EPA compiled plant-specific details on FGD wastewater flow rates and discharge destinations, existing FGD wastewater treatment details, and use of on-site and off-site landfills by steam electric power plants operating wet FGD systems. As part of the 2015 rule, EPA developed a similar set of input information from the Steam Electric Survey data, site visits, sampling episodes, and other industry-provided data to calculate compliance costs. For the final rule, EPA updated the input values using additional information gathered from industry, public comments on the proposed rule, and information available from the Department of Energy (see Section 2). EPA developed a list of EGUs expected to incur FGD wastewater treatment compliance costs by identifying plants that operate wet FGD systems, taking into account changes made to their FGD treatment system, and EGUs that, since the 2015 rule, have retired or converted to a fuel other than coal. EPA also identified EGUs that have announced plans to retire or convert their fuel source between December 31, 2023 and December 31, 2028. This section describes the updates to cost inputs from the 2015 rule.

EPA modified the overall cost methodology to account for two FGD wastewater flow rates for each plant discharging FGD wastewater: (1) the FGD purge flow rate and (2) the optimized FGD flow rate. The FGD purge flow rate is the typical amount of wastewater from the FGD scrubber

[23] EPA evaluated costs for three different methods of concentrate management. EPA evaluated costs associated with (1) encapsulation of the brine (or membrane reject) and transporting the solidified material to a landfill; (2) disposing of the brine via a commercial deepwell injection site; and (3) using a crystallizer to treat the brine and transport the resulting solid material to a landfill.

that is sent to FGD wastewater treatment. The optimized FGD flow is a reduced FGD wastewater flow that takes into account a reduction in FGD wastewater purged from the system, where equipment metallurgy could accommodate increased chloride concentration in the FGD system. EPA used the FGD purge flow rate (i.e., the pre-optimized flow rate) to calculate capital costs and the optimized FGD flow rate to estimate O&M costs, recognizing that well-operated plants would take steps to optimize the volume of water to be treated and normalize the flow where possible.

FGD Purge Flow Rate

For plants where there were no retirements or fuel conversions of wet-scrubbed EGUs, EPA calculated the non-optimized FGD purge flow rates using the same methodology that was used for the 2015 rule (ERG, 2020g). For those plants where one or more wet-scrubbed EGUs have been retired or converted to a non-coal fuel source (or have plans to do so by 2023), EPA updated FGD purge flow rates, taking into account that FGD wastewater would no longer be produced by the retired/converted EGUs.

EPA used NPDES permit data to calculate FGD purge flow rates for new wet FGD systems that began operation since the 2015 rule. For plants whose permits were not available or did not specify a flow rate, EPA estimated FGD purge flows using the amount of coal burned in a year and a factor for the median FGD flow rate per ton of coal burned per year. EPA used data from Form EIA-923 to determine the type and amount of coal burned by each scrubbed unit and calculated the unit-level FGD purge flows using Equation 5-1.

$$\text{Unit-Level FGD Purge Flow (GPD)} = \text{Coal Burned} \times \text{Median Flow per Ton of Coal}$$

Equation 5-1

Where:

Coal Burned	=	The reported coal burned by the steam electric EGUs serviced by a wet FGD system (in tons per year). Data from 2018 Form EIA-923.
Median Flow per Ton of Coal	=	The calculated median FGD wastewater flow rate per ton of coal burned, by the type of coal burned at the EGU: 0.1454 for bituminous, 0.0392 for subbituminous, 0.2313 for lignite, and 0.1017 for any coal blend (in GPD/ton/year). Values were developed using data collected from the Steam Electric Survey (ERG, 2020g).

EPA summed the unit-level FGD purge flow rates to estimate plant-level FGD purge flow rates for new steam electric power plants and new wet FGD systems.

EPA used the FGD purge flow rates to calculate capital costs, which may overestimate the size and cost of the treatment system that plants would actually install; however, EPA chose to use

this flow rate for capital costs to ensure that installed treatment technologies would be able to accommodate the maximum possible FGD purge flow.

Optimized FGD Flow Rate

EPA's cost analyses for the 2015 rule took into account that certain higher-flow plants would find it beneficial to take steps to optimize FGD purge flow as a way to reduce the size and associated cost of the FGD wastewater treatment system. During the 2015 rulemaking, EPA recognized that flow optimization was a viable approach for plants of all sizes; however, at that time, EPA accounted for such actions only for those plants with FGD purge flows greater than 1 million gallons per day (MGD) and where equipment metallurgy could accommodate the resulting increased chloride concentration in the FGD system. Since the 2015 rule, site visits, meetings with industry representatives, and other information EPA has confirmed that flow optimization is a realistic step that plants can take to reduce compliance costs. Many plants, including those with FGD purge flow rates well below 1 MGD, anticipate implementing flow optimization approaches as they upgrade their FGD wastewater treatment. Because of this, EPA's cost analyses for this final rule incorporate flow optimization for all wet-scrubbed plants where FGD system metallurgy can accommodate it.

In the cost analyses, EPA adjusted the FGD purge flow described above by the flow optimization algorithm to determine the plant-level optimized FGD flow rate. For these optimized FGD flow rates, EPA concluded that plants would optimize the FGD flow through the treatment system by either throttling down the purge flow or recycling a portion of the purge stream back to the FGD system. One effect of this reduced discharge flow is that chloride concentrations will increase somewhat (the mass of chlorides discharged would remain unchanged while the volume of water decreases; thus, the lower flow rate will contain a higher concentration of chlorides). EPA used the Steam Electric Survey data to determine plant-specific FGD system constraints for maximum design chloride concentrations and operating chloride concentrations. Consistent with the flow minimization methodology used for the 2015 rule, EPA identified individual plants as having the potential to optimize FGD purge flow if the operating chloride concentration is lower than 80 percent of the maximum design concentration. If the operating chloride concentration is not lower than 80 percent of the maximum design concentration, EPA assumed that further flow optimization was not practical and the resulting optimized FGD flow rate is equal to the FGD purge flow. EPA calculated the degree of flow optimization using Equation 5-2; this represents the percent by which the FGD purge can easily be reduced without threatening the metallurgical integrity of the FGD system.

$$\text{Plant-Specific Degree of Flow Optimization} = (\text{Design Max Cl Level} \times 0.8 - \text{Operating Cl Level}) / (0.8 \times \text{Design Cl Level})$$

Equation 5-2

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Where:

Design Max Cl Level	=	Design maximum chlorides concentration as reported in Part B, Section 4 of the Steam Electric Survey (B4-3), or a design concentration specified in comments during the rulemaking for the 2015 rule (in ppm).
Operating Cl Level	=	Chlorides concentration in the FGD scrubber purge as reported in Part B, Section 5 of the Steam Electric Survey (B5-3) (in ppm). Where data were not available in Part B, Section 5, the maximum operating chloride concentration from Part B, Section 4 of the Steam Electric Survey (B4-2) was used.

EPA limited the degree of flow optimization for each plant so that the resulting operating chloride level would not exceed 30,000 ppm or 80 percent of the plant-specific design maximum chloride level, whichever is lower.[24]

For any existing plant that did not have sufficient information in the Steam Electric Survey to calculate a plant-specific degree of flow optimization, or where data were available but considered confidential business information (CBI), the median plant-specific degree of flow optimization was used, 0.375.[25] EPA calculated optimized FGD flows using the plant-specific degree of flow optimization in Equation 5-3.

$$\text{Optimized FGD Flow (GPD)} = \text{FGD Purge Flow} \times (1 - \text{Plant-Specific Degree of Flow Optimization})$$

Equation 5-3

Where:

FGD Purge Flow	=	For FGD systems included in 2015 rule population, plant-level FGD purge flow updated for retirements and refuels; for new FGD systems, plant-level FGD purge flow (sum of unit-level flows, calculated using Equation 5-1) in GPD.

[24] Data in the record shows that biological treatment systems operate without impairment at chloride concentrations well above 30,000 ppm and TDS concentrations well over 100,000 ppm. Nevertheless, recognizing that power companies have expressed preference to operate such systems at moderate chloride levels, EPA's cost analyses are based on operating the FGD system so that chloride concentrations in the FGD purge do not routinely exceed 30,000 ppm.

[25] EPA calculated the median plant-specific degree of flow optimization using the 2015 rule FGD population.

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Plant-Specific Degree of Flow Optimization	=	The smallest system-level degree of flow optimization for each plant (calculated using Equation 5-2) or the median plant-specific degree of flow reduction, 0.375).

All new FGD systems identified since the 2015 rule were not adjusted to reflect any degree of flow optimization; instead, because they are expected to be operating as designed, EPA set the optimized FGD flow equal to the FGD purge flow.

To estimate O&M costs, EPA used optimized FGD flow rates, recognizing that well-operated plants would take steps to optimize the volume of water to be treated and normalize the flow where possible, which will allow for more realistic annual cost estimates. Implementing flow optimization is the more cost-effective approach for operating the treatment systems, and also has commensurate benefits such as enhanced worker safety since smaller volumes of treatment chemicals will require reduced handling by the operators.

FGD Treatment-In-Place Data

EPA identified data on each plant's current level of treatment for its FGD wastewater (ERG, 2020n). For plants that are already treating the FGD wastewater using some form of chemical precipitation, biological treatment, or evaporation treatment, EPA identified which specific treatment system components would still be needed to comply with the final rule and based estimates of the compliance costs on the specific equipment upgrades. The cost methodologies in Section 5.2.2 through Section 5.2.5 discuss treatment-in-place considerations for the different technology options evaluated for the final rule.

Landfill Data

Like the 2015 rule, EPA used data from the Steam Electric Survey and other public sources to identify which plants operate on-site active/inactive landfills containing FGD solids. Plants without an on-site active/inactive landfill with combustion residuals were identified as off-site landfills. EPA anticipates plants with on-site inactive landfills will resume disposal of FGD solids to the landfill if needed for implementation of an FGD technology option.

Final CCR Part A Decision Data

As discussed in Section 3.3, EPA updated the FGD population for changes in plant operations as a result of the CCR Part A rule. The CCR Part A rule sets requirements for managing impoundments and landfills containing CCRs. Based on the CCR Part A rule requirements, EPA expects that all plants with unlined or clay-lined impoundments will alter how they operate their current CCR impoundments by either rerouting CCR waste, installing new CCR-compliant impoundments, or installing tank-based treatment. EPA developed a methodology to use EPA's impoundment liner data , described in Section 3.3, to predict operational changes at each coal-fired power plant under the CCR Part A rule. EPA identified plants with unlined or clay-lined CCR surface impoundments. Where all CCR surface impoundments are impacted by the CCR Part A rule, EPA assumed that the plant would install tank-based treatment. For FGD wastewater, this tank-based treatment is assumed to be equivalent to the chemical precipitation

system described in Section 5.2.2. See Table 5-1 for details on how plants installing tank-based treatment under the CCR Part A rule were reflected in FGD wastewater cost and loadings estimates.

Table 5-1. ELG FGD Changes Accounting for CCR Part A Rule

CCR Part A Rule Decision	ELG Technology Basis Assumptions	Effect on ELG Compliance Costs	Effect on ELG Pollutant Loadings
All CCR surface impoundments expected to close or retrofit.	Plant installs BAT chemical precipitation system, getting full treatment-in-place credit.	Chemical precipitation treatment-in-place. For baseline, plants incur the following capital and O&M costs: Mercury analyzer Compliance monitoring All biological treatment system costs (including transportation/disposal)	Chemical precipitation treatment-in-place.
At least one CCR surface impoundment is not expected to close or retrofit.	No change.	No change.	No change.
No data.	No change.	No change.	No change.

EPA identified 30 plants discharging FGD wastewater operating all unlined or clay-lined CCR surface impoundments. Of these, 23 plants already operate chemical precipitation or more advanced FGD wastewater treatment (e.g., biological treatment or thermal systems). EPA expects the remaining seven plants will install a chemical precipitation system under the CCR Part A rule.

5.2.2 Cost Methodology for Chemical Precipitation

As described in the preamble, costs for chemical precipitation as a stand-alone treatment technology were estimated for a specific subcategory. Costs for chemical precipitation were also estimated as a pretreatment component for the VIP option. The design basis used to estimate costs for chemical precipitation treatment systems is consistent with the 2015 rule and includes the following process steps:

- Flow equalization.
- Hydroxide precipitation, sulfide precipitation and iron coprecipitation using lime, organosulfide, and ferric chloride chemical addition in separate reaction tanks.
- Polymer addition and clarification to remove precipitants and other suspended solids.
- Acid addition for pH neutralization.
- Sand filtration for additional removal of suspended solids.

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EPA used data from the 2015 rule to develop cost curves representing the capital and O&M costs for the chemical precipitation treatment system. The cost curves presented below include the following components:

- Purchased Equipment Costs.
  - Pumps.
  - Tanks and mixers.
  - Reactors.
  - Chemical feed systems.
  - Clarifiers.
  - Filter presses.
  - Sand filters.
  - Pollutant monitoring and analysis (including a mercury analyzer).
- Direct Capital Costs.
  - Purchased equipment (including fabricated equipment and process machinery).
  - Freight.
  - Purchased equipment installation.
  - Instrumentation and controls (installed).
  - Piping (installed).
  - Electrical (installed).
  - Buildings (including services).
  - Site preparation.
- Indirect Capital Costs.
  - Engineering and supervision.
  - Construction expenses.
  - Contractor's fees.
  - Contingency.
- O&M Costs.
  - Operating labor.
  - Maintenance materials and labor.
  - Chemical purchase.
  - Energy.
  - Sludge transportation and disposal.
  - Compliance monitoring.

Section 9.6.1 of the 2015 TDD provides additional details on the design basis for chemical precipitation wastewater treatment systems. EPA also calculated 6-year recurring costs to replace the mercury analyzer separately from the cost curves, as described below.

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Plant-Level Capital and O&M Cost

EPA used 2015 rule cost data and FGD purge flows to generate cost curves for estimating plant-level capital and O&M costs as a function of FGD purge flow rate and optimized FGD flow rate in GPD, respectively.[26] Because costs are affected by the solids disposal location (i.e., on-site landfill or off-site transportation and disposal), EPA generated a set of cost curves for each transportation and disposal method (see Figure 5-1 and Figure 5-3 for capital costs and Figure 5-2 and Figure 5-4 for O&M costs). These cost curves reflect the costs to design, procure, install, and operate chemical precipitation treatment at plants where all components of the treatment system will need to be acquired, such as at plants operating surface impoundments to treat the FGD wastewater. To estimate plant-specific capital and O&M costs, EPA used the appropriate curves based on whether or not the plant is identified as having an on-site or off-site landfill, as described in Section 5.2.1.

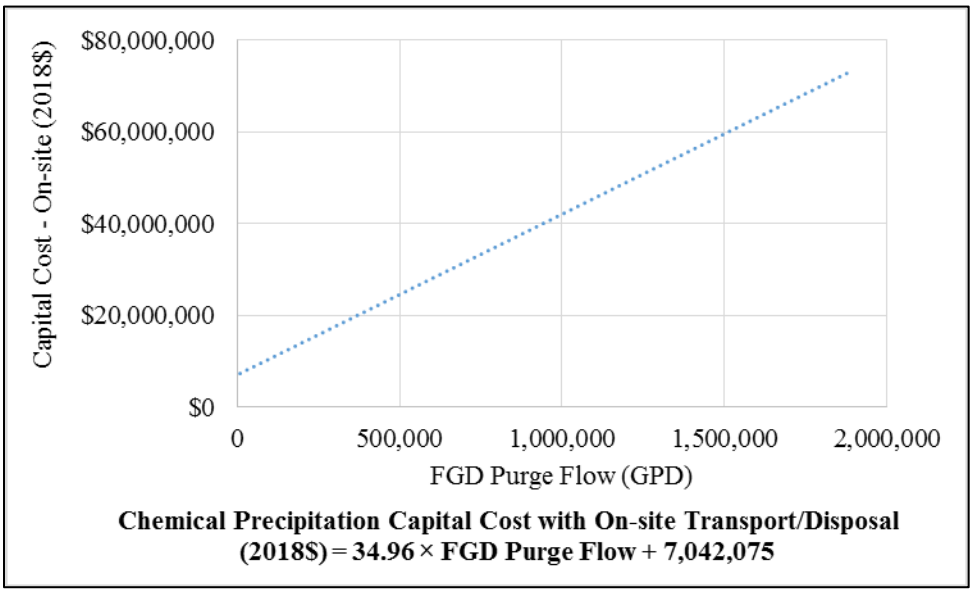


Figure 5-1. Chemical Precipitation Capital Cost Curve – On-site Transport/Disposal

[26] EPA adjusted the 2015 rule original cost data basis from 2010 to 2018 dollars using RS Means Historical Cost Indexes.

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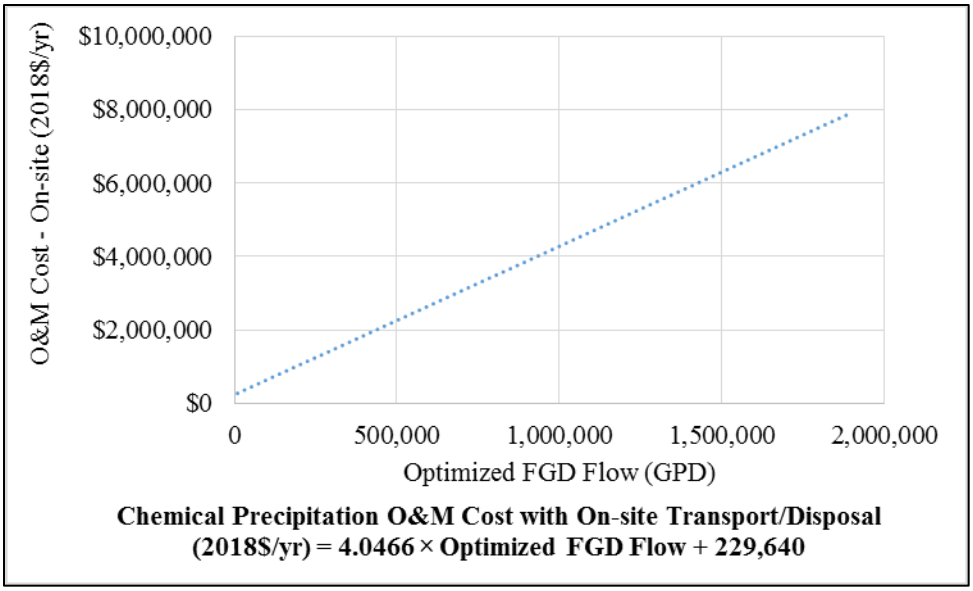


Figure 5-2. Chemical Precipitation O&M Cost Curve – On-site Transport/Disposal

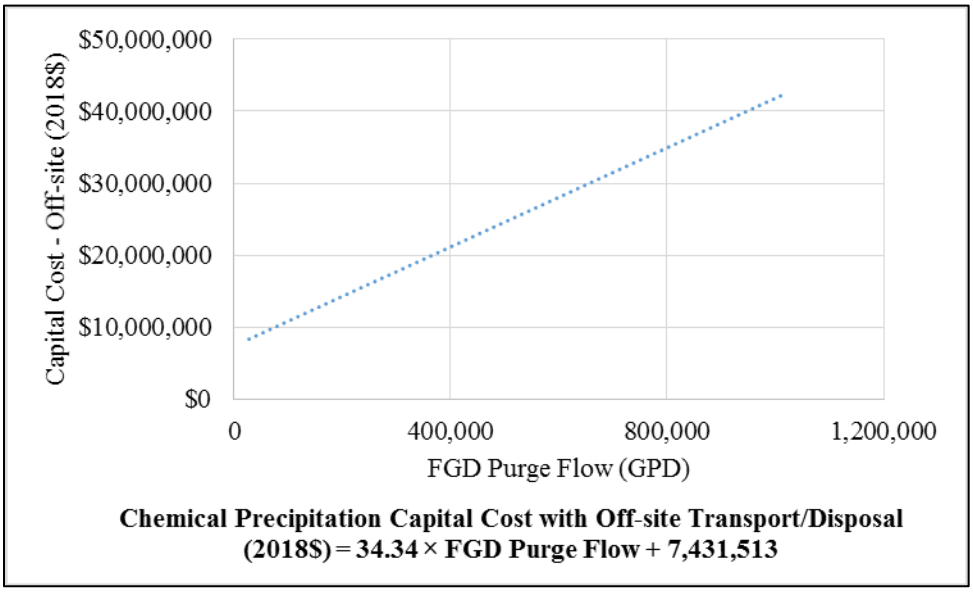


Figure 5-3. Chemical Precipitation Capital Cost Curve – Off-site Transport/Disposal

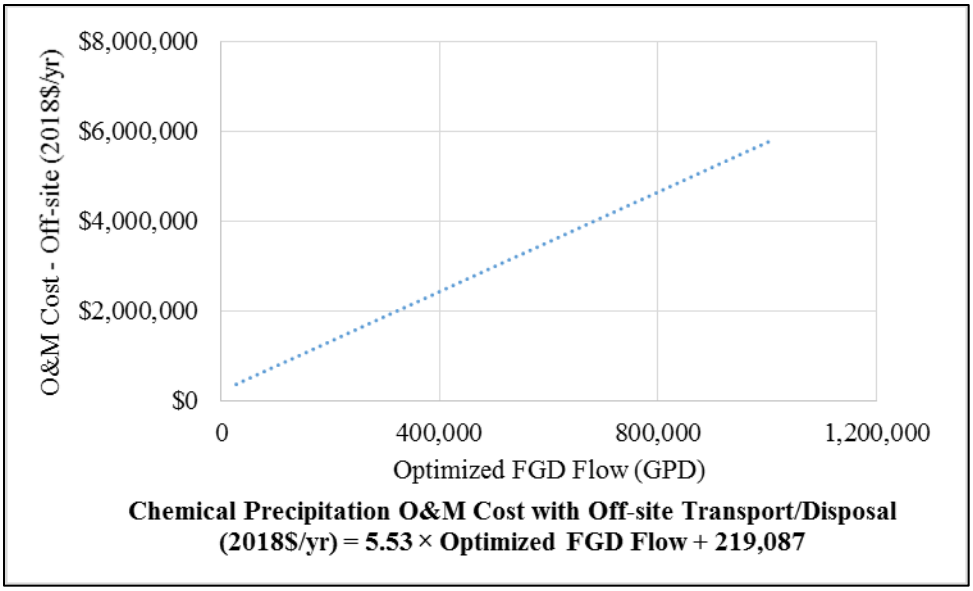


Figure 5-4. Chemical Precipitation O&M Cost Curve – Off-site Transport/Disposal

Recurring Costs

EPA's cost analyses include additional costs for the chemical precipitation system that would be incurred periodically after installation but less frequently than annually. EPA determined that a prudently designed treatment system would include a continuous water quality monitor for measuring mercury concentrations in the treatment system effluent. The mercury analyzer technology has been demonstrated as highly effective for FGD wastewater, and by providing near real-time results, it has enabled plant operators to proactively take steps to adjust the chemical precipitation process as needed to optimize pollutant removal. EPA assumed that the expected life of a mercury analyzer is 6 years and that each plant will operate one analyzer for FGD wastewater. Plants with full or partial chemical precipitation costs incur a cost of $100,000 (2018$) to replace the mercury analyzer every 6 years.

Treatment-In-Place Adjustment for Capital and O&M Costs

For each plant that already has components of chemical precipitation treatment in place as part of its treatment system, EPA used Steam Electric Survey data to identify any upgrades needed to make the treatment system comport with the chemical precipitation design basis considered for the final rule. Depending on the capital upgrades needed or additional O&M costs that would be incurred, EPA used guidelines presented in Table 5-2 to classify the plant as incurring high, medium, or low capital costs and high, medium, or low O&M costs. Then, for each classification, EPA used cost data from the 2015 rule to calculate the median percentage of costs incurred by the plant compared to a full chemical precipitation treatment system (ERG, 2020f). The median percentages are presented in Table 5-2; these values were used to estimate the compliance costs that would be incurred by plants that already operate some components of the model chemical precipitation treatment system.

Table 5-2. Percentage of Chemical Precipitation Costs Incurred by Plants with Treatment in Place

Cost Category	Capital Costs		O&M Costs	
	Category Guidelines	Percent of Full Treatment System Cost Incurred	Category Guidelines	Percent of Full Treatment System Cost Incurred
High	Plants expected to incur costs for an equalization tank and other equipment, such as a sand filter or chemical addition system.	27%	Plants expected to incur more than two chemical costs in addition to a mercury analyzer and monitoring (e.g., three chemical costs or two chemical costs and another O&M cost).	31%
Medium	Plants expected to incur costs for only an equalization tank (all or partial) or plants costed for a sand filter and chemical addition systems.	17%	Plants expected to incur costs for up to two chemicals, in addition to a mercury analyzer and monitoring.	13%
Low	Plants expected to incur costs for a mercury analyzer and for up to two chemical addition systems.	1%	Plants expected to incur costs for a mercury analyzer, monitoring, and minimal chemical costs.	6%

For plants with existing tank-based FGD wastewater treatment (i.e., not an impoundment system), EPA calculated costs following the framework shown in Table 5-3. Partial capital and O&M costs were calculated using the appropriate percentage of full treatment system cost incurred from Table 5-2 for each plant. Compliance monitoring costs include sampling labor and materials as well as the costs associated with sample preservation, shipping, and analysis. EPA estimated the annual cost for compliance monitoring to be $73,600 (in 2018 dollars).

Table 5-3. Costs Incurred for Chemical Precipitation for Plants with Existing Treatment in Place

Treatment in Place	Cost Incurred
Partial Chemical Precipitation	Partial capital and O&M costs (see Table 5-2)
Full Chemical Precipitation [a]	Compliance monitoring costs
Chemical Precipitation followed by LRTR, HRTR or other biological process (e.g., Suspended Growth Biological Treatment)	Compliance monitoring costs
Evaporation [b]	Zero costs

a – A full chemical precipitation treatment system includes ferric chloride, organosulfide, polymer, and acid addition, and/or meets the mercury and arsenic limitations established for chemical precipitation.

b – Reusing the treated effluent from evaporation treatment systems as scrubber makeup water or in other applications is more cost-effective than discharging this wastestream.

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5.2.3 Cost Methodology for Chemical Precipitation followed by LRTR (CP+LRTR)

The design basis to estimate costs for CP+LRTR includes both chemical precipitation cost components (see Section 5.2.2) and LRTR cost components. The LRTR components of the model treatment technology include the following:

- Purchased Equipment Costs.
  - Anoxic/anaerobic bioreactors.
  - Control skids.
  - Backwash skids.
  - Tanks.
  - Pumps.
  - Heat exchanger.
  - Pretreatment system (for denitrification at applicable plants).
  - Ultrafilter.
  - Chemical feed skids.
  - Pollutant monitoring and analysis (including a mercury analyzer).
- Direct Costs.
  - Purchased equipment (including fabricated equipment and process machinery).
  - Freight.
  - Instrumentation and controls (installed).
  - Piping (installed).
  - Electrical (installed).
  - Buildings (including services).
  - Site preparation.
- Indirect Costs.
  - Engineering and supervision.
  - Contingency.
- O&M Costs.
  - Operating labor.
  - Maintenance labor.
  - Chemical purchase.
  - Energy.

Plant-Level Capital and O&M Cost

EPA's approach for estimating capital and O&M costs for the chemical precipitation pretreatment stage of the CP+LRTR model technology is similar to the methodology described

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in Section 5.2.2.[27] Cost curves for the pretreatment stage with on-site disposal of treatment residuals are presented in Figure 5-5 and Figure 5-6; Figure 5-7 and Figure 5-8 present costs for pretreatment at plants that dispose of treatment residuals off site. To estimate plant-specific capital and O&M costs, EPA used the appropriate curves based on whether the plant is identified as having an on-site or off-site landfill, as described in Section 5.2.1.

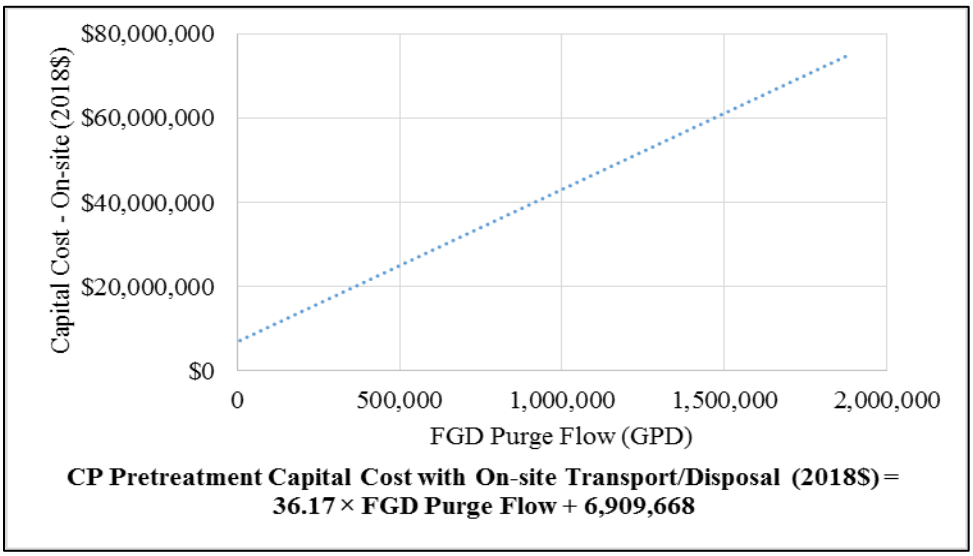


Figure 5-5. CP Pretreatment Capital Cost Curve – On-site Transport/Disposal

[27] These costs differ slightly from those presented in Section 5.2.2 due to additional components, including additional pumps, tanks, and piping, to account for holding and transporting partially treated water before further treatment in the LRTR system.

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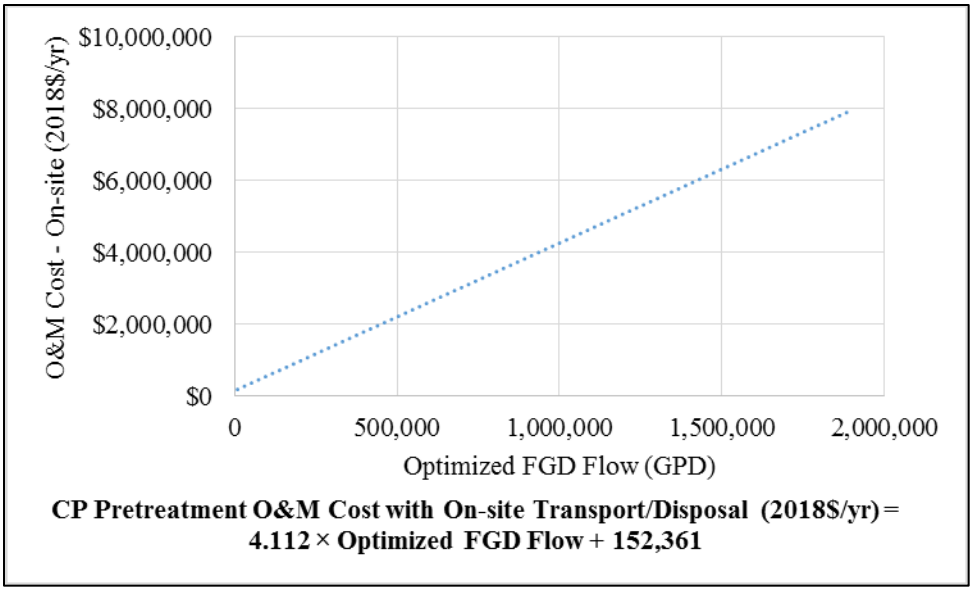


Figure 5-6. CP Pretreatment O&M Cost Curve – On-site Transport/Disposal

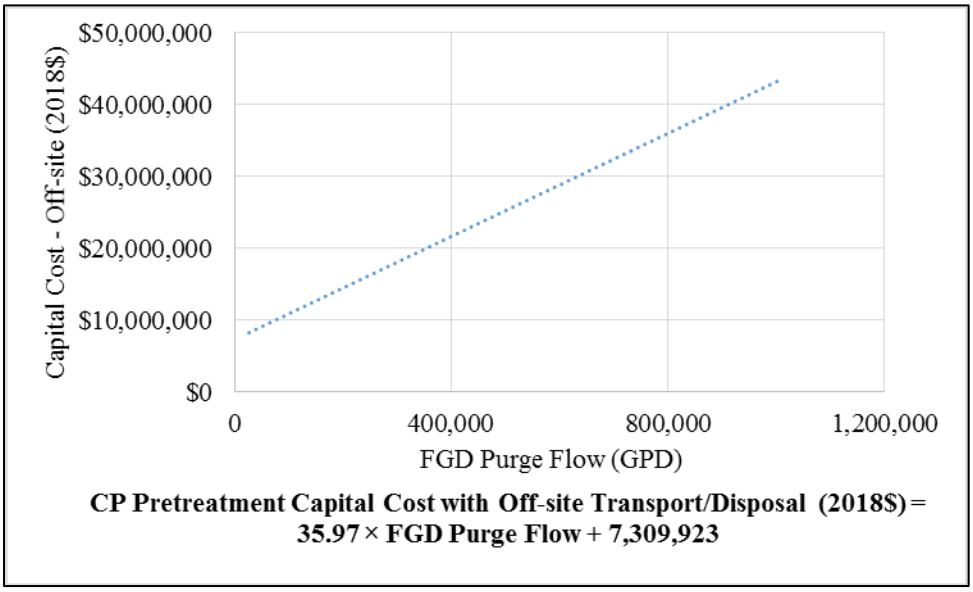


Figure 5-7. CP Pretreatment Capital Cost Curve – Off-site Transport/Disposal

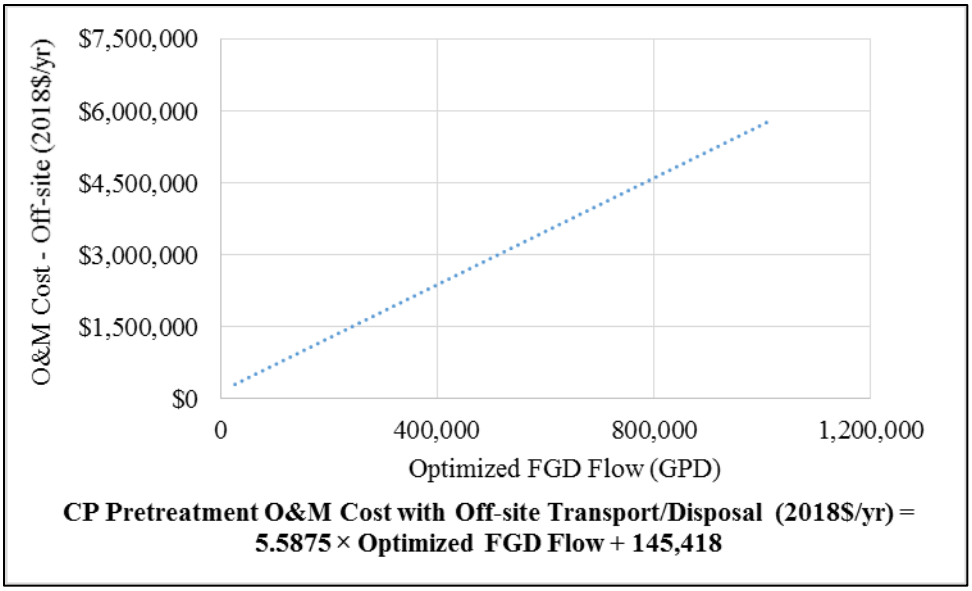


Figure 5-8. CP Pretreatment O&M Cost Curve – Off-site Transport/Disposal

EPA used cost information compiled for the 2015 rule, combined with additional data collected since then from power companies, treatment equipment vendors, engineering firms, and publicly available engineering cost references to develop capital and O&M cost curves for the LRTR stage of the CP+LRTR model technology (ERG, 2020i). The resulting cost curves differentiate between plants that may need to include an additional partial denitrification pretreatment step (for the model LRTR treatment technology, this was defined as plants with influent nitrate concentrations higher than 50 mg/L in untreated FGD purge). EPA used low nitrates curves to estimate costs for all plants, except for the subset of plants where sampling data from the Analytical Database (ERG, 2015) and the Steam Electric Survey (ERG, 2020i) demonstrated nitrate/nitrite concentrations at or above 50 mg/L in FGD purge.

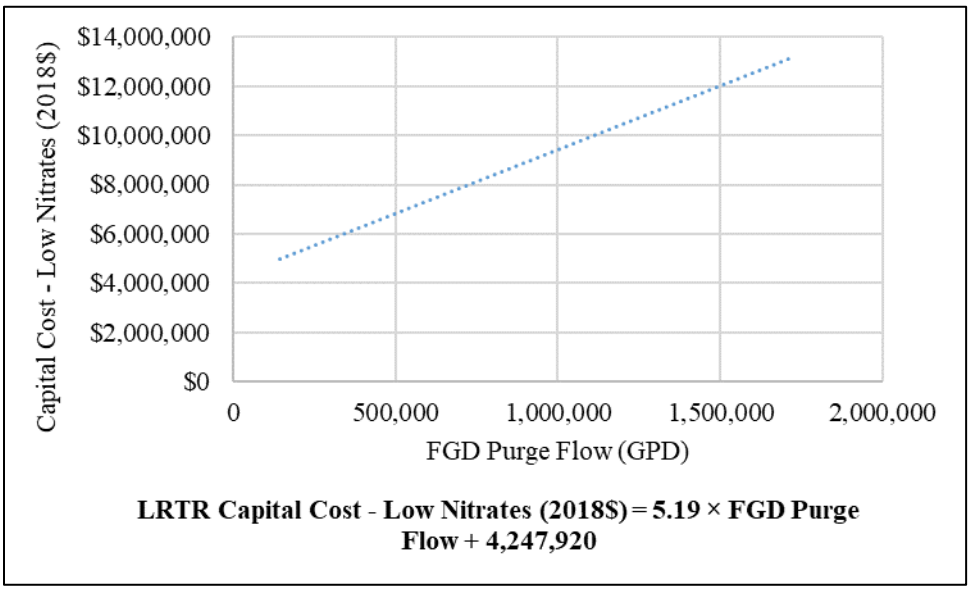


Figure 5-9. LRTR Capital Cost Curve – Low Nitrates

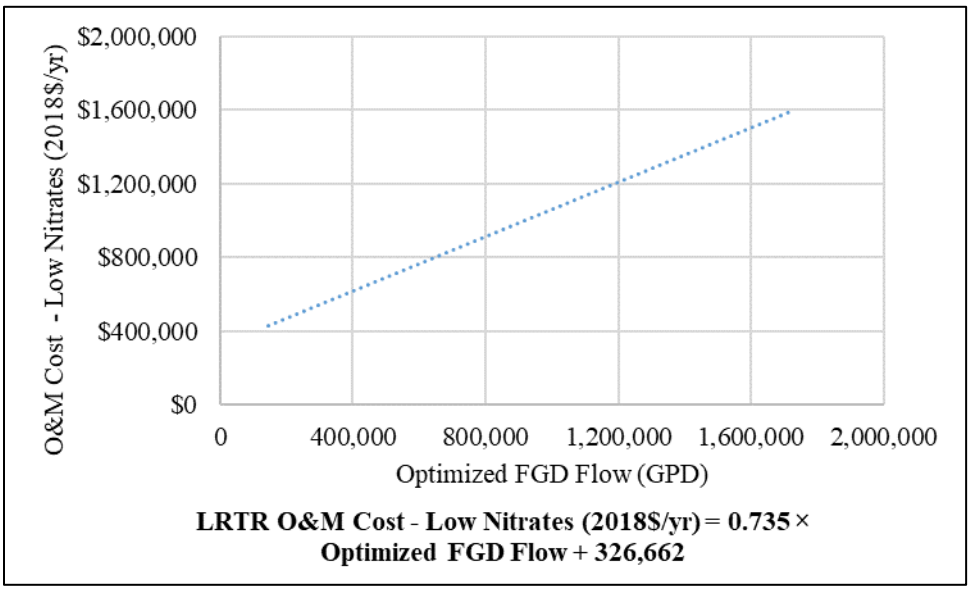


Figure 5-10. LRTR O&M Cost Curve – Low Nitrates

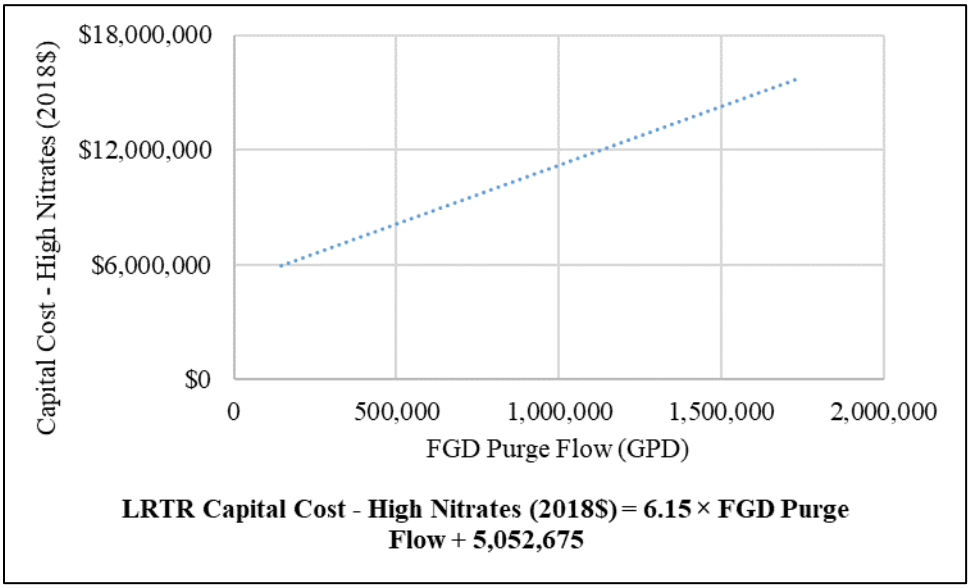


Figure 5-11. LRTR Capital Cost Curve – High Nitrates

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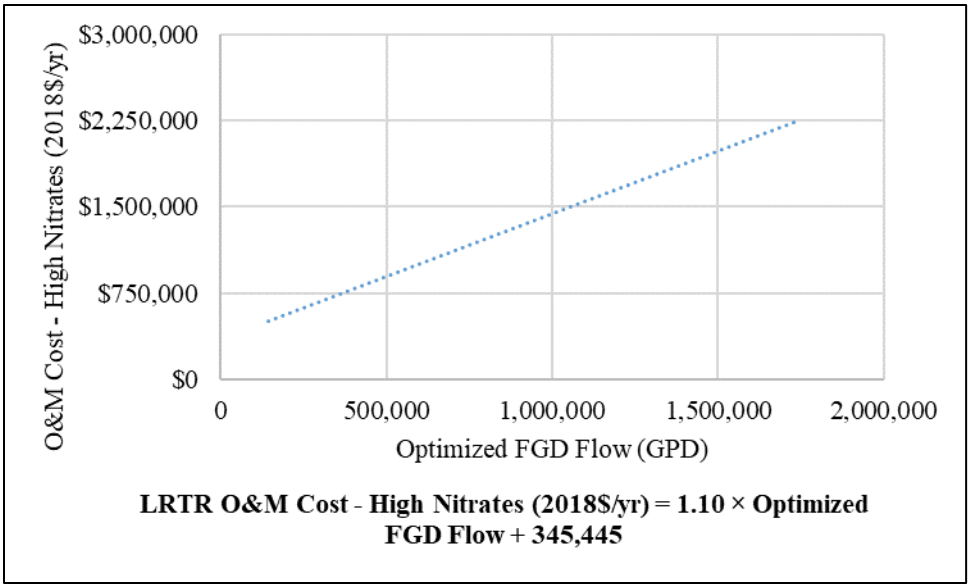


Figure 5-12. LRTR O&M Cost Curve – High Nitrates

Recurring Costs

For all plants that are expected to incur costs beyond compliance monitoring, EPA calculated the 6-year recurring cost for a mercury analyzer, as discussed in Section 5.2.2.

Treatment-In-Place Adjustment for CP+LRTR Capital and O&M Costs

For plants with FGD wastewater treatment in place (beyond an impoundment system), EPA calculated the plant cost based on the costs listed in Table 5-4. Equalization tank capital costs are equivalent to the median cost for a field erected equalization tank with a hydraulic residence time of 24 hours for flows between 70,000 GPD and 1,000,000 GPD for the 2015 rule costed population ($823,000). Compliance monitoring O&M costs for the CP+LRTR technology option include costs to conduct annual compliance monitoring for arsenic, mercury, selenium, and nitrate/nitrite ($75,600).

Table 5-4. Costs Incurred for Chemical Precipitation plus LRTR for Plants with Existing Treatment in Place

Treatment in Place	Cost Incurred
Partial Chemical Precipitation	Partial chemical precipitation as pretreatment capital and O&M costs (see Section 5.2.2 and Table 5-3), full LRTR capital and O&M costs based on plant-specific nitrate/nitrite concentrations.
Full Chemical Precipitation [a]	Full LRTR capital and O&M costs based on plant-specific nitrate/nitrite concentrations.
Chemical Precipitation followed by Suspended Growth Biological Treatment	Equalization tank capital cost and compliance monitoring costs.

Table 5-4. Costs Incurred for Chemical Precipitation plus LRTR for Plants with Existing Treatment in Place

Treatment in Place	Cost Incurred
Chemical Precipitation followed by LRTR or HRTR	Compliance monitoring costs.
Evaporation [b]	Zero costs

a – A full chemical precipitation treatment system includes ferric chloride, organosulfide, polymer, and acid addition, and/or meets the mercury and arsenic limitations established for chemical precipitation.

b – Reusing the treated effluent from evaporation treatment systems as scrubber makeup water or in other applications is more cost-effective than discharging this wastestream.

5.2.4 Cost Methodology for Chemical Precipitation followed by HRTR (CP+HRTR)

The CP+HRTR technology basis presented here is consistent with the BAT technology basis for the 2015 rule, chemical precipitation followed by anoxic/anaerobic biological treatment. The cost estimates for this technology option include the chemical precipitation cost components described in Section 5.2.2, as well as the following HRTR cost components:

- Purchased Equipment Costs.
  - Anoxic/anaerobic biological system.
  - Tanks.
  - Pumps.
  - Heat exchanger (for applicable plants).
  - Backwash system.
  - Chemical feed systems.
  - Pretreatment system (for denitrification at applicable plants).
  - Pollutant monitoring and analysis (including a mercury analyzer ORP monitor).
- Direct Capital Costs.
  - Purchased equipment (including fabricated equipment and process machinery).
  - Freight.
  - Purchased equipment installation.
  - Instrumentation and controls (installed).
  - Piping (installed).
  - Electrical (installed).
  - Buildings (including services).
  - Site preparation.
- Indirect Capital Costs.
  - Engineering and supervision.
  - Construction expenses.
  - Contractor’s fees.

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  - Contingency.
- O&M Costs.
  - Operating labor.
  - Maintenance materials and labor.
  - Chemical purchase.
  - Energy.
  - Sludge transportation and disposal.
  - Compliance monitoring.

Section 9.6.2 of the 2015 TDD provides additional details on the design basis for HRTR.

Plant-Level Capital and O&M Cost

EPA estimated pretreatment costs for a chemical precipitation system using the equations found in Section 5.2.3. Like the method described in Section 5.2.2 for chemical precipitation, EPA used the 2015 rule data to establish cost curves for HRTR capital and O&M costs as a function of FGD purge flows and optimized FGD flows, respectively (ERG, 2020j). Based on data received following promulgation of the 2015 rule, EPA adjusted HRTR costs to account for increased installation costs. EPA also converted the 2015 rule costs from a cost basis of 2010 dollars to 2018 dollars. EPA generated a set of cost curves for both on-site and off-site transportation and disposal (see Figure 5-13 and Figure 5-15 for capital costs and Figure 5-14 and Figure 5-16 for O&M costs). To estimate plant-specific capital and O&M costs, EPA used the appropriate curves based on whether the plant is identified as having an on-site or off-site landfill, as described in Section 5.2.1.

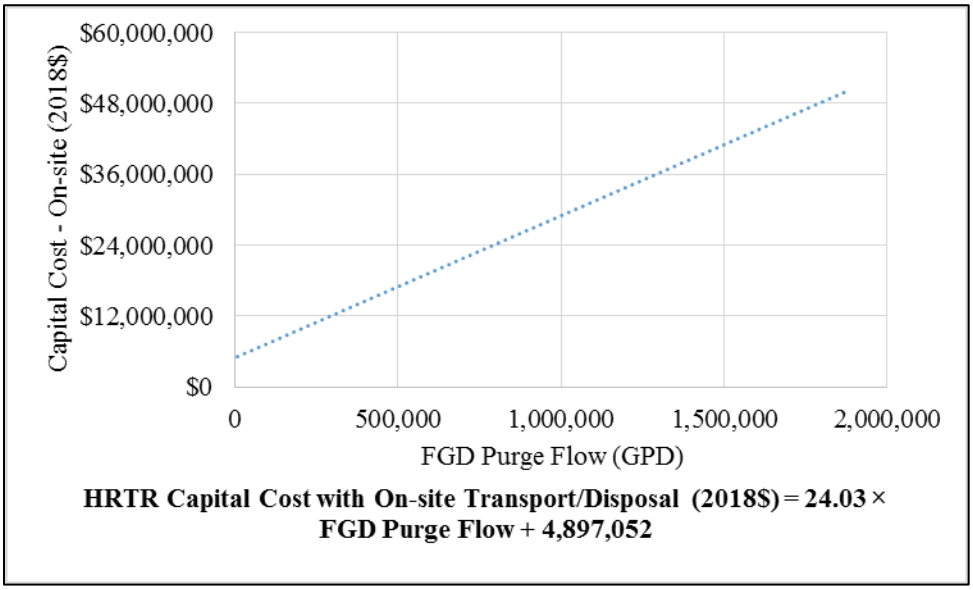


Figure 5-13. HRTR Capital Cost Curve – On-site Transport/Disposal

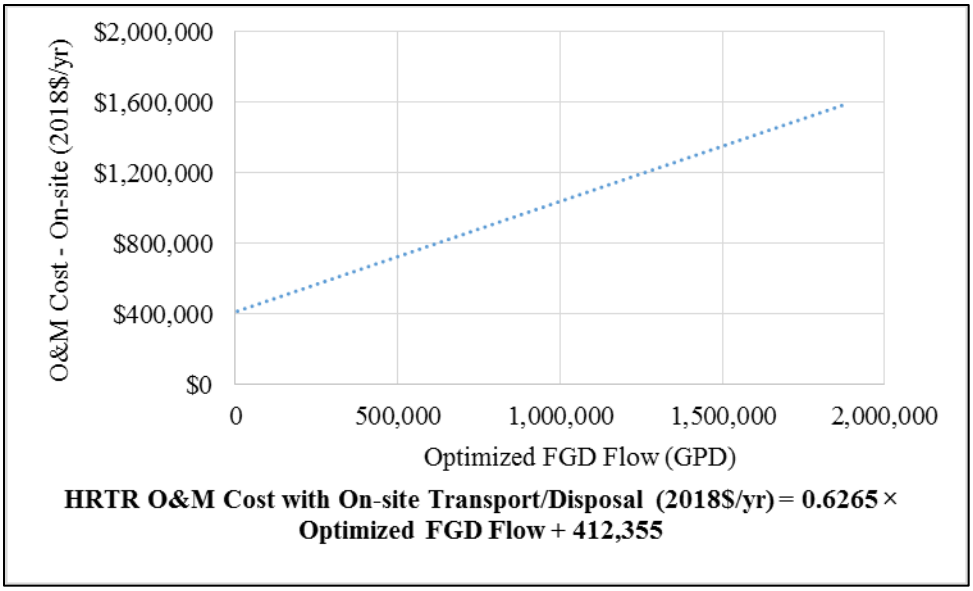


Figure 5-14. HRTR O&M Cost Curve – On-site Transport/Disposal

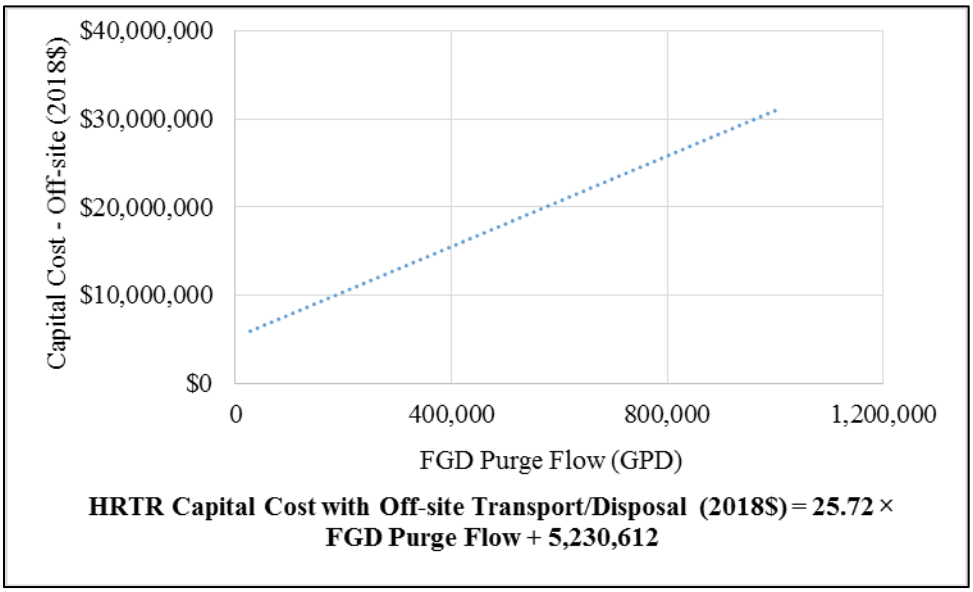


Figure 5-15. HRTR Capital Cost Curve – Off-site Transport/Disposal

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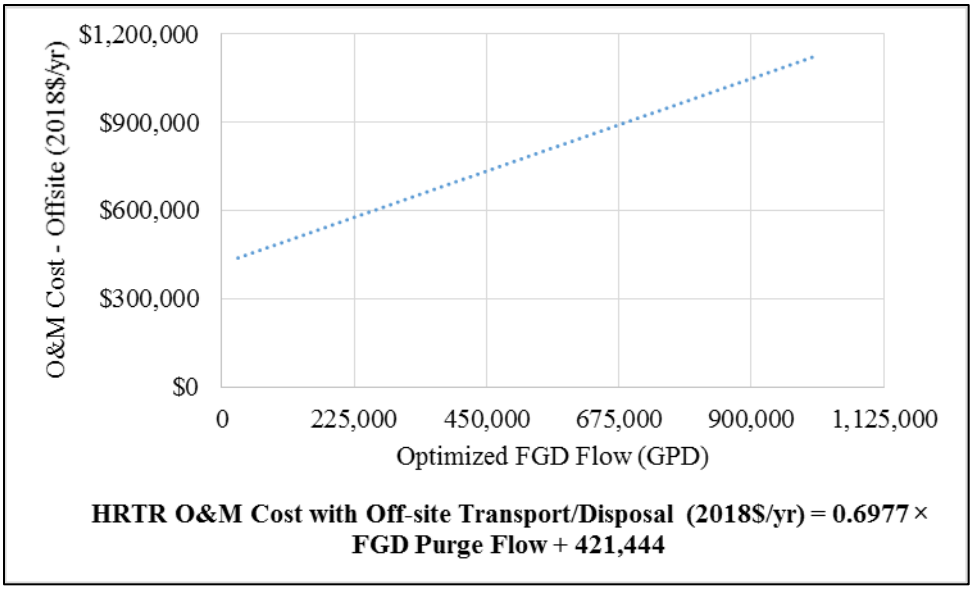


Figure 5-16. HRTR O&M Cost Curve – Off-site Transport/Disposal

For plants with a nitrate/nitrite concentration in the FGD purge at or above 100 mg/L, EPA estimated additional capital and O&M costs for a denitrification treatment step using the 2015 rule methodology (Equation 5-4 and Equation 5-5). EPA used low nitrates curves to estimate costs for all plants except for the subset of plants where sampling data from the Analytical Database and the Steam Electric Survey demonstrated nitrate/nitrite concentrations at or above 100 mg/L in FGD purge (ERG, 2015).

$$\text{Denitrification Capital Costs (2018\$)} = -1.091 \times [(\text{FGD Purge Flow}) / (24 \text{ hr/day}) / (60 \text{ min/hr})]^2 + 3{,}601.1 \times [(\text{FGD Purge Flow}) / (24 \text{ hr/day}) / (60 \text{ min/hr})] + 501{,}971$$

Equation 5-4

$$\text{Denitrification O\&M Costs (2018\$)} = 2{,}699 \times [(\text{Optimized FGD Flow}) / (24 \text{ hr/day}) / (60 \text{ min/hr})] + 275{,}333$$

Equation 5-5

Recurring Costs

For all plants that are expected to incur costs beyond monitoring, EPA calculated the 6-year recurring cost for a mercury analyzer, as discussed in Section 5.2.2.

Treatment-in-Place Adjustment for Plant-Level Capital and O&M Costs

For plants with existing FGD wastewater treatment more advanced than a surface impoundment, EPA calculated the plant cost based on the costs listed in Table 5-5. Equalization tank capital costs are equivalent to the median cost for a field erected equalization tank with a hydraulic residence time of 24 hours for flows between 70,000 GPD and 1,000,000 GPD for the 2015 rule

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costed population ($823,000). Compliance monitoring costs for the CP+HRTR technology option include costs to collect and analyze effluent samples for arsenic, mercury, selenium, and nitrate/nitrite, following the cost methodology used for the 2015 rule and converting to 2018 dollars ($75,600).

Table 5-5. Costs Incurred for Chemical Precipitation plus HRTR for Plants with Existing Treatment in Place

Treatment in Place	Cost Incurred
Partial Chemical Precipitation	Partial chemical precipitation as pretreatment capital and O&M costs (see Section 5.2.2 and Table 5-2), full HRTR capital and O&M costs based on plant-specific nitrate/nitrite concentrations
Full Chemical Precipitation [a]	Full HRTR capital and O&M costs based on plant-specific nitrate/nitrite concentrations
Chemical Precipitation followed by LRTR or Suspended Growth Biological Treatment	Equalization tank capital cost and compliance monitoring costs
Chemical Precipitation followed by HRTR	Compliance monitoring costs
Evaporation [b]	Zero costs

a – A full chemical precipitation treatment system includes ferric chloride, organosulfide, polymer, and acid addition, and/or meets the mercury and arsenic limitations established for chemical precipitation.

b – Reusing the treated effluent from evaporation treatment systems as scrubber makeup water or in other applications is more cost-effective than discharging this wastestream.

5.2.5 Cost Methodology for Membrane Filtration

The design basis for the membrane technology option includes pretreatment with chemical precipitation, membrane filtration, and concentrate (i.e., brine) management. EPA updated costs for encapsulation of the membrane reject using encapsulation and supplemented these costs with two additional concentrate management alternatives:

- Thermal treatment of the brine using crystallization.
- Disposal of the brine using commercial injection wells (i.e., deepwell injection).

The membrane filtration process produces a permeate stream that is higher quality than the water used in the FGD system for limestone slurry makeup, mist eliminator wash, and other processes. Because the FGD system is a net water consumer, plants using this treatment technology would most likely recycle the permeate within the FGD process operations; therefore, no compliance monitoring costs would be incurred.

EPA used capital and O&M cost data collected from industry sources and technology vendors to develop cost methodologies that estimate plant-specific costs for pretreatment with chemical precipitation, membrane filtration, concentrate management, and disposal of solids. The design basis to estimate costs for membrane filtration includes both chemical precipitation cost components (see Section 5.2.2) and membrane cost components. The membrane treatment technology basis includes the following cost components:

- Purchased Equipment Costs.
  - Membrane filtration skids.
  - Tanks.
  - Pumps.
  - Concentrate management equipment: For encapsulation, brine mixing skid. For crystallization, crystallizer body, heat exchanger, vapor condenser, compressors, and ducting. Deepwell injection does not have any associated purchased equipment costs.
- Direct Capital Costs.
  - Purchased equipment (including fabricated equipment and process machinery).
  - Freight.
  - Purchased equipment installation.
  - Instrumentation and controls (installed).
  - Piping (installed).
  - Electrical (installed).
  - Buildings (including services).
  - Site preparation.
- Indirect Capital Costs.
  - Engineering and supervision.
  - Construction expenses.
  - Contractor's fees.
  - Contingency.
- O&M Costs.
  - Operating labor.
  - Maintenance materials and labor.
  - Chemical purchase.
  - Energy.
  - Sludge transportation and disposal. [28]

The following sections describe the cost methodology for each concentrate management alternative evaluated as part of the membrane filtration option and present the cost curves EPA used to estimate plant-level compliance costs. Throughout the remaining sections of this development document, the term "membrane filtration" refers to the membrane filtration technology option using encapsulation as the concentrate management alternative as it was estimated to be the least costly brine management alternative at all plants.

[28] Where necessary, these transportation and disposal costs include a capital and O&M component. For disposal of encapsulated or crystallized material in on-site landfills, costs to maintain and expand an existing landfill and to transport material to the landfill are included. For disposal of encapsulated or crystallized material in off-site landfills, costs to use commercial landfills and to transport material to the landfill are included. For disposal of brine via deepwell injection, costs to use commercial wells and transport material are included.

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Plant-Level Capital and O&M Cost: Membrane Filtration with Encapsulation

EPA estimated pretreatment costs for a chemical precipitation system using the equations found in Section 5.2.3. Plants with existing treatment more advanced than surface impoundments were considered to have sufficient pretreatment for effective treatment through the membrane. For these plants, membrane filtration and encapsulation cost data (not including pretreatment) were used to establish relationships between capital costs and FGD purge flow rates, and between O&M costs and optimized FGD flow rates, respectively (ERG, 2020k). Similar to methodologies for other treatment technologies, EPA constructed curves to differentiate between on-site and off-site transportation and disposal. Costs for all plants were estimated using the Membrane Filtration with Encapsulation curves (see Figure 5-17 and Figure 5-19 for capital cost curves and Figure 5-18 and Figure 5-20 for O&M cost curves). To estimate plant-specific capital and O&M costs,

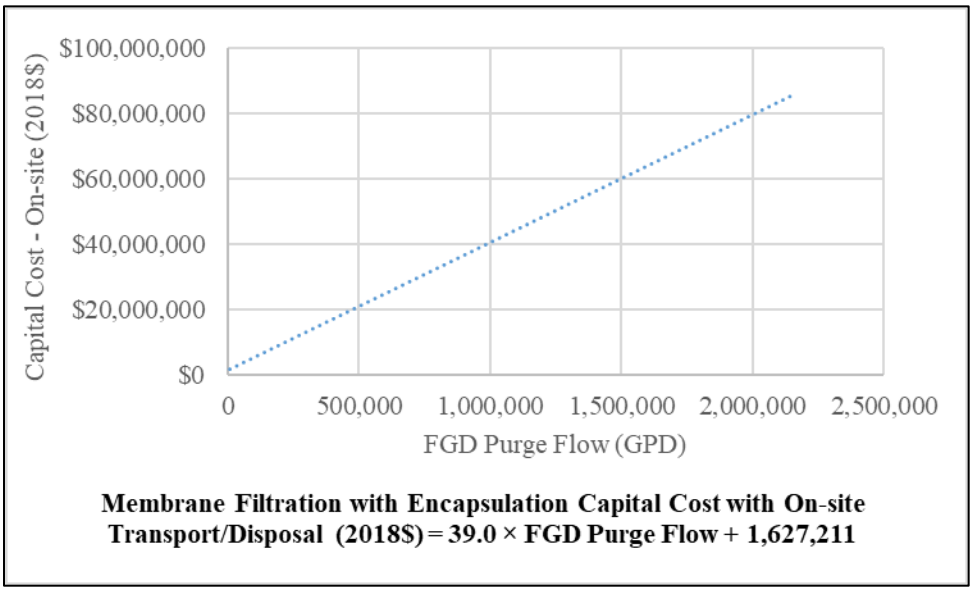


Figure 5-17. Membrane Filtration with Encapsulation Capital Cost Curve – On-site Transport/Disposal

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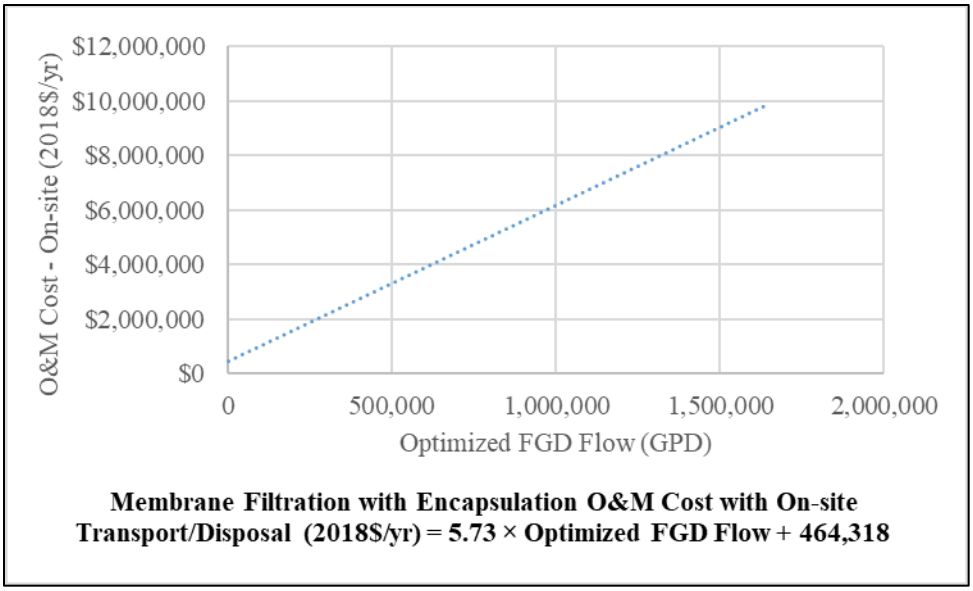


Figure 5-18. Membrane Filtration with Encapsulation O&M Cost Curve – On-site Transport/Disposal

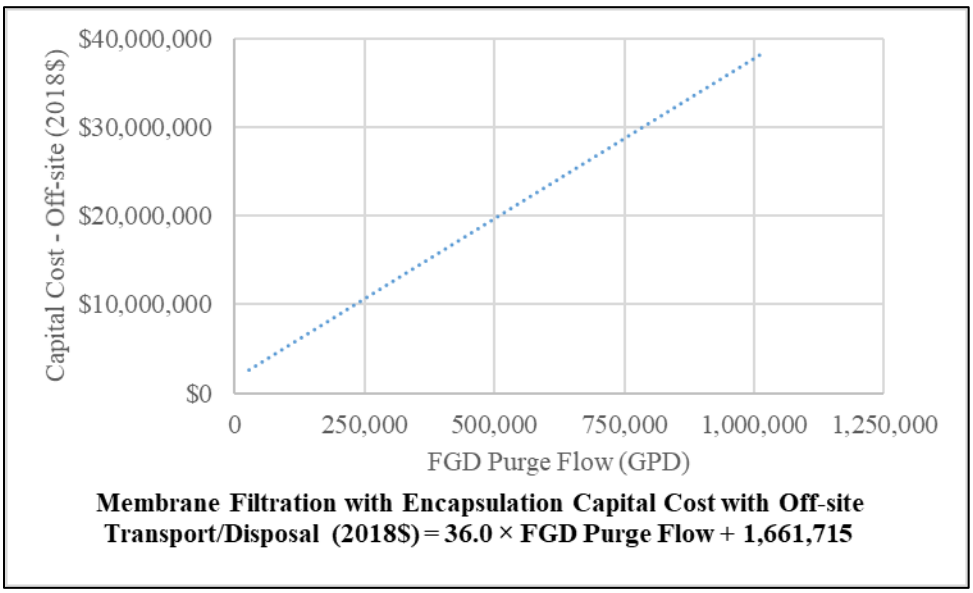


Figure 5-19. Membrane Filtration with Encapsulation Capital Cost Curve – Off-site Transport/Disposal

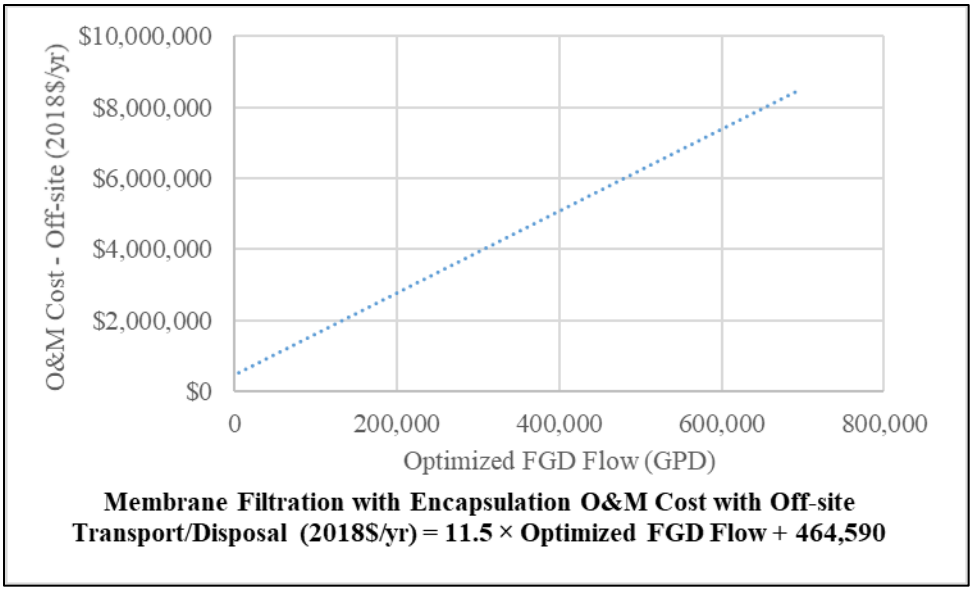


Figure 5-20. Membrane Filtration with Encapsulation O&M Cost Curve – Off-site Transport/Disposal

Plant-Level Capital and O&M Cost: Membrane Filtration with Crystallization

EPA estimated pretreatment costs for a chemical precipitation system using the equations found in Section 5.2.3. Plants with existing treatment more advanced than surface impoundments were considered to have sufficient pretreatment for effective treatment through the membrane. Membrane filtration and crystallization cost data (not including pretreatment) were used to establish relationships between capital costs and FGD purge flow rates, and between O&M costs and optimized FGD flow rates, respectively (ERG, 2020l). Similar to methodologies for other treatment technologies, EPA constructed curves to differentiate between on-site and off-site transportation and disposal. Costs for all plants were estimated using the Membrane Filtration with Crystallization curves (see Figure 5-21 and Figure 5-23 for capital cost curves and Figure 5-22 and Figure 5-24 for O&M cost curves). To estimate plant-specific capital and O&M costs, EPA used the appropriate curves based on whether the plant is identified as having an on-site or off-site landfill, as described in Section 5.2.1.

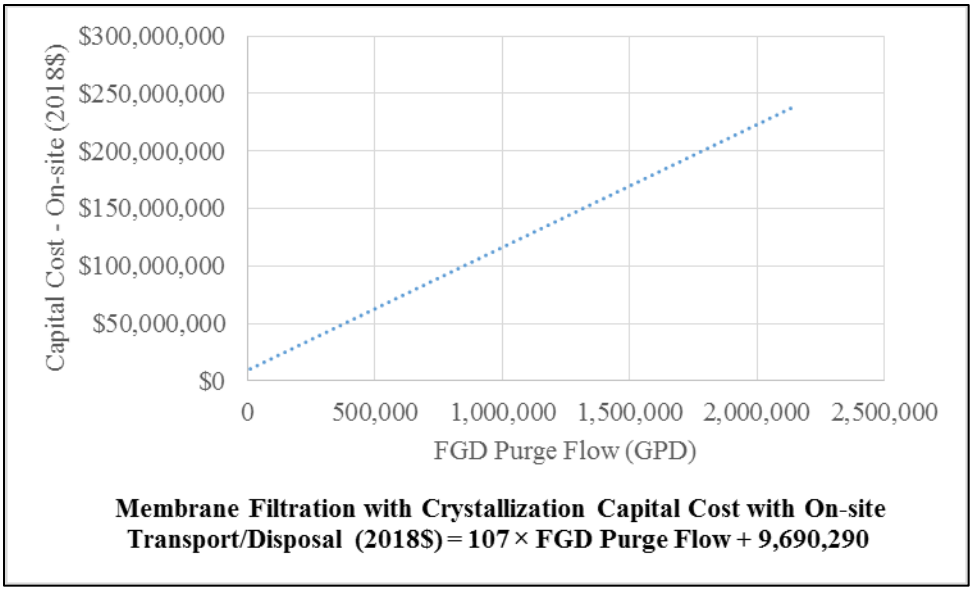


Figure 5-21. Membrane Filtration with Crystallization Capital Cost Curve – On-site Transport/Disposal

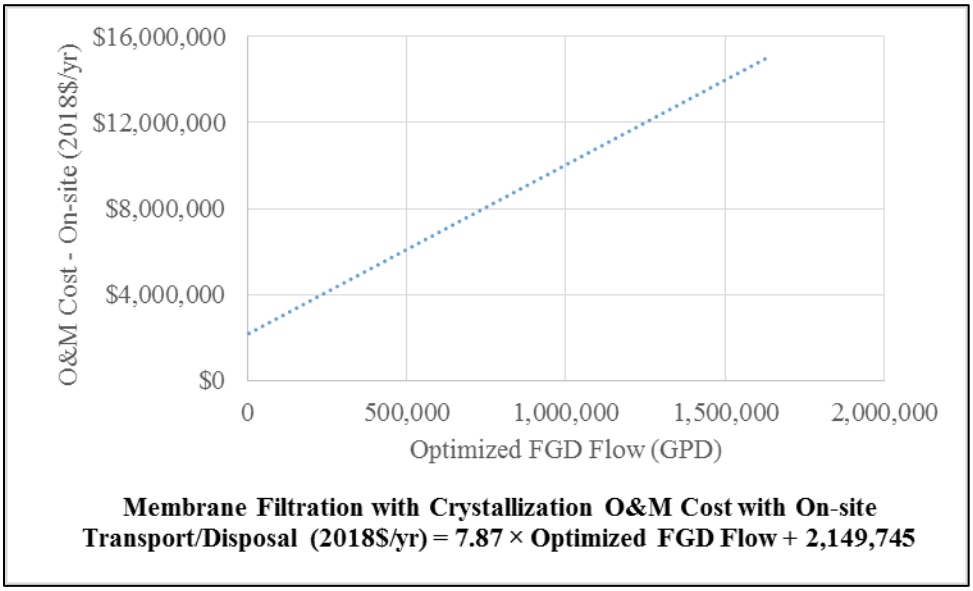


Figure 5-22. Membrane Filtration with Crystallization O&M Cost Curve – On-site Transport/Disposal

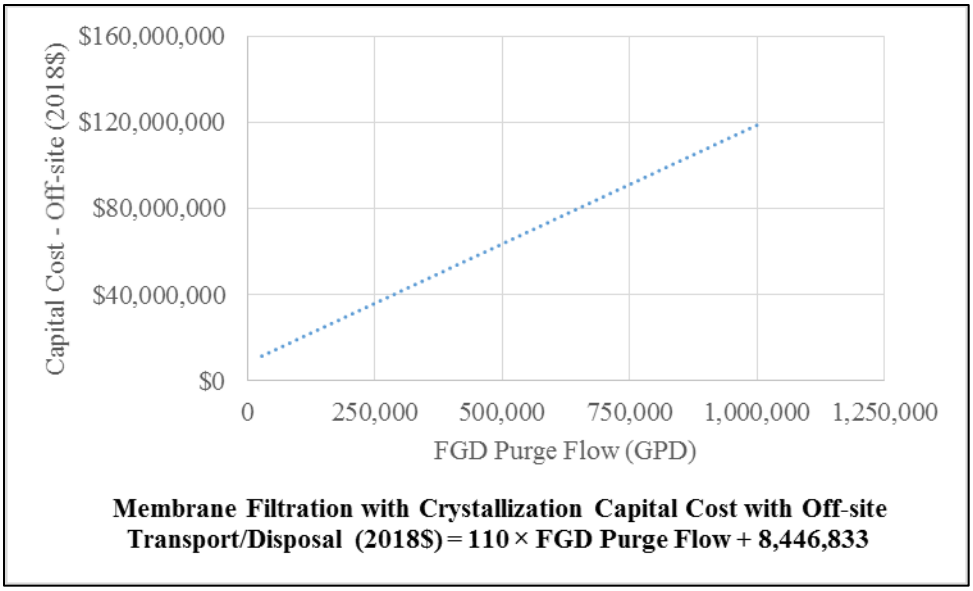


Figure 5-23. Membrane Filtration with Crystallization Capital Cost Curve – Off-site Transport/Disposal

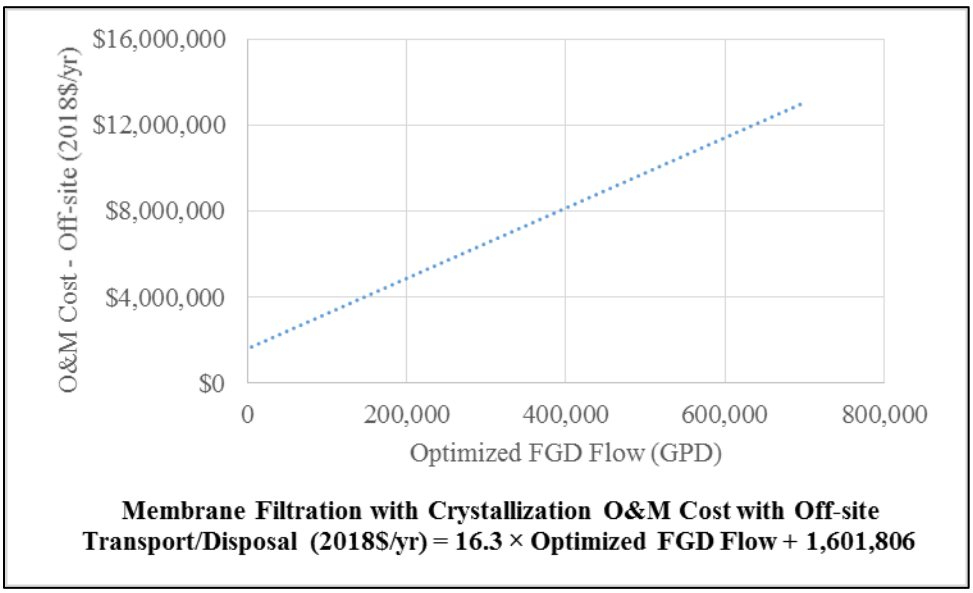


Figure 5-24. Membrane Filtration with Crystallization O&M Cost Curve – Off-site Transport/Disposal

Plant-Level Capital and O&M Cost: Membrane Filtration with Deepwell Injection

EPA estimated pretreatment costs for a chemical precipitation system using the equations found in Section 5.2.3. Plants with existing treatment more advanced than surface impoundments were considered to have sufficient pretreatment for effective treatment through the membrane. Because there are no capital costs associated with deepwell injection, only membrane filtration cost data (not including pretreatment) were used to establish a relationship between capital costs

and FGD purge flow rates (ERG, 2020m). Membrane filtration and deepwell injection cost data were used to establish a relationship between O&M costs and optimized FGD flow rates (ERG, 2020i). Costs for all plants were estimated using the Membrane Filtration, and Membrane Filtration with Deepwell Injection curves (see Figure 5-25 for the capital cost curve and Figure 5-26 for the O&M cost curve).

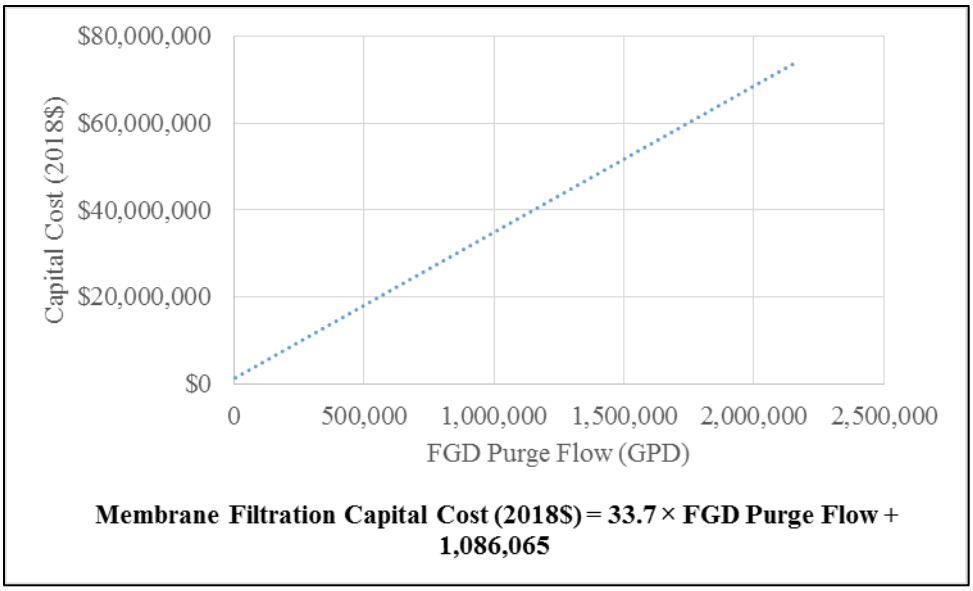


Figure 5-25. Membrane Filtration Capital Cost Curve

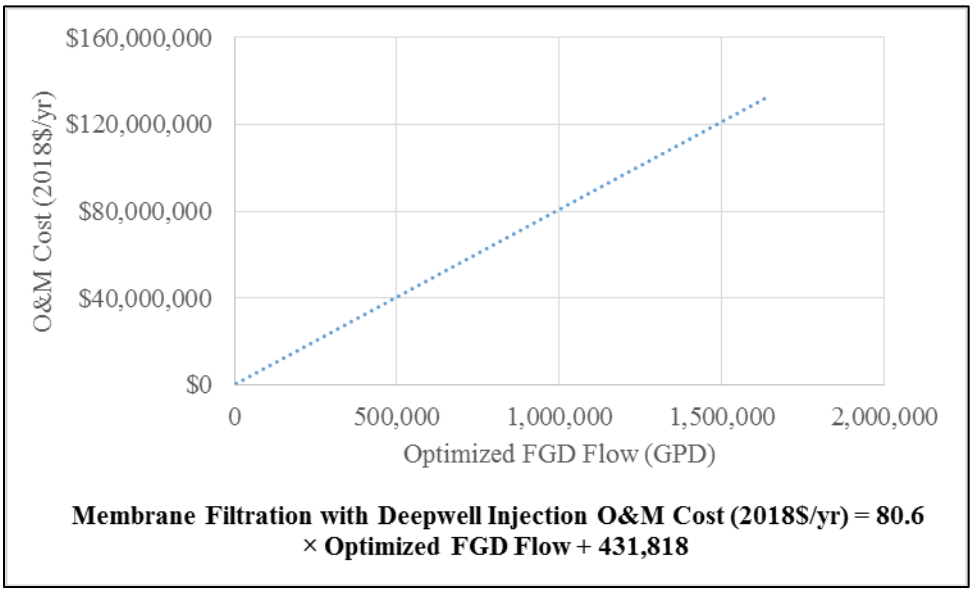


Figure 5-26. Membrane Filtration with Deepwell Injection O&M Cost Curve

Treatment-in-Place Adjustment for Plant-Level Capital and O&M Costs

For plants with existing FGD wastewater treatment in place more advanced than a surface impoundment, EPA calculated the plant cost for membrane filtration using any of the concentrate management alternatives based on the costs listed in Table 5-6. See Section 5.2.2 and Table 5-2 for additional details on how partial chemical precipitation costs are estimated.

Table 5-6. Membrane Filtration TIP Summary of Costs

Treatment in Place	Cost Incurred
Partial or Full Chemical Precipitation, LRTR, HRTR, or Suspended Growth Treatment.	Membrane only capital and O&M costs.
Evaporation [a]	Zero costs.
Other Treatment in Place.	Full capital and O&M costs.

a – Reusing the treated effluent from evaporation treatment systems as scrubber makeup water or in other applications is more cost-effective than discharging this wastestream.

In addition, plants that currently discharge FGD wastewater to a publicly owned treatment works (POTW) receive a cost savings for treating their wastewater on site and ceasing discharges to the POTW, unique to the membrane filtration technology option. EPA identified one plant from the Steam Electric Survey data that discharges FGD wastewater to a POTW. Using the POTW-specific rate structures, EPA estimated the annual costs incurred by this plant for discharging to a POTW and deducted these annual costs (ERG, 2020k).

5.2.6 Methodology for Estimating Cost Savings from Ceasing Use of FGD Surface Impoundments

When plants install more advanced FGD wastewater treatment, they will experience some cost savings associated with ceasing operations of the FGD wastewater surface impoundment(s). This decrease in impoundment operations costs will offset the cost to operate the new treatment system, to some degree. EPA estimated the annual O&M and recurring costs associated with on-site impoundments and subtracted these costs from the estimated compliance costs for the technologies described above in this section, consistent with the 2015 methodology. The FGD impoundment operating cost savings quantified by EPA include costs associated with the following:

- Wastewater transport system (i.e., pipelines, vacuum source) used to pump wastewater from the FGD scrubber to the impoundment.
- Impoundment site (i.e., general operation of the impoundment and inspections).
- Wastewater treatment processes (e.g., pH control).
- Water recycle system at the impoundment (if applicable).
- FGD earthmoving costs (e.g., front-end loader, removing/stacking combustion residuals at the impoundment site).

EPA used Steam Electric Survey data to identify plants that have at least one impoundment containing FGD wastewater and at least one EGU not designated as retired or planned. For those plants that have upgraded the FGD wastewater treatment system since the 2015 rule, EPA

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assumed that their impoundments would cease operation.[29] EPA estimated plant-level costs for operating impoundments based on the total amount of FGD solids currently handled wet at the plant. EPA estimated the total FGD impoundment O&M cost savings using Equation 5-6.

Total FGD Impoundment O&M Cost Savings (2018$/yr) = (FGD Impoundment Operating Cost Savings + FGD Earthmoving Cost Savings) × (2018 Cost Index / 2010 Cost Index)

Equation 5-6

Where:

FGD Impoundment Operating Cost Savings	=	Impoundment operating cost savings (in 2010$) (see Equation 5-9).
FGD Earthmoving Cost Savings	=	O&M cost associated with the earthmoving equipment required (in 2010$) (see Equation 5-11).
2010 Cost Index	=	183.5, the RSMeans Historical Cost Index for 2010.
2018 Cost Index	=	215.8, the RSMeans Historical Cost Index for 2018.

FGD Impoundment Operating Annual Cost Savings

EPA estimated the FGD impoundment operating cost savings by first calculating the plant megawatt (MW) factor and the plant-specific unitized cost using Equation 5-7 and Equation 5-8.

$$\text{Plant MW Factor (MW)} = 7.569 \times (\text{Plant Size})^{-0.32}$$

Equation 5-7

Where:

Plant Size	=	Plant size (in MW). The plant nameplate capacity for only those EGUs serviced by a wet FGD system (from responses to Question A1-13 in the Steam Electric Survey).

Plant-Specific Unitized Cost (2010$/ton) = (Impoundment Operating Unitized Cost) × (Plant MW Factor)

Equation 5-8

[29] Once the FGD wastewater treatment system is upgraded to a more advanced technology (e.g., CP+LRTR), the impoundment provides little value with respect to pollutant removal and remains a substantial liability (for example, due to structural integrity failure).

Where:

Impoundment Operating Unitized Cost	=	The unitized annual cost to operate a combustion residual impoundment. EPA used the unitized cost value of $7.35 (in 2010$/ton).
Plant MW Factor	=	Factor to adjust combustion residual handling costs based on plant capacity (in MW) (see Equation 5-7).

Next, EPA estimated the total amount of FGD solids handled wet using the optimized FGD flow rate in GPD described in Section 5.2.1 and the average total suspended solids (TSS) concentration from EPA's Field Sampling Program, which was conducted in support of the 2015 rule. EPA calculated the FGD impoundment operating cost savings by multiplying the plant-specific unitized cost (see Equation 5-8) by the amount of wet FGD solids using Equation 5-9.

FGD Impoundment Operating Cost Savings (2010$/year) = (Plant-Specific Unitized Cost) × [(Optimized FGD Flow) × (Average TSS Concentration) × (3.785 L/gal) × (0.001 g/mg) × (1.102×10^{-6} tons/g) × (365 days/year)]

Equation 5-9

Where:

Optimized FGD Flow	=	Optimized FGD flow rate (in GPD) (see Equation 5-3).
Average TSS Concentration	=	The average influent TSS concentration for FGD wastewater treatment influent sampled as part of the 2015 rule (16,760 mg/L) (ERG, 2015).

FGD Earthmoving Annual Cost Savings

To calculate FGD earthmoving cost savings, EPA first calculated the plant-specific front-end loader unitized cost by multiplying the plant MW factor and the front-end loader unitized cost using Equation 5-10.

Plant-Specific Front-End Loader Unitized Cost (2010$) = (Front-End Loader 2010 Unitized O&M Cost) × (Plant MW Factor)

Equation 5-10

Where:

Front-End Loader Unitized O&M Cost	=	The unitized cost value that represents the operation and maintenance of the front-end loader used to redistribute FGD solids at an impoundment. This value was calculated to be $2.49 (in 2010$/ton).

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Plant MW Factor	=	Factor to adjust combustion residual handling costs based on plant capacity (in MW) (see Equation 5-7).

Next, EPA estimated the amount of combustion residuals (in tons) using the plant's optimized FGD flow, in gallons per day, and the average TSS concentration from EPA's Field Sampling Program. EPA calculated the FGD earthmoving cost savings using Equation 5-11.

FGD Earthmoving Cost Savings (2010$/yr) = (Plant-Specific Front-End Loader Unitized Cost) × [(Optimized FGD Flow) × (Average TSS Concentration) × (3.785 L/gal) × (0.001 g/mg) × (1.102 x 10^{-6} tons/g) × (365 days/year)]

Equation 5-11

Where:

Optimized FGD Flow	=	Optimized FGD flow rate (in GPD) (see Equation 5-3 in Section 5.2.1).
Average TSS Concentration	=	The average influent TSS concentration for FGD wastewater treatment influent sampled as part of EPA Steam Electric Rulemaking effort (16,760 mg/L) (ERG, 2015).

FGD Earthmoving Recurring Costs

EPA calculated 10-year recurring cost savings associated with operating the earthmoving equipment (i.e., front-end loader) by determining the cost and average expected life of a front-end loader. EPA determined the 2018 cost of the earthmoving equipment to be $474,000 and assumed that the expected life of a front-end loader is 10 years. EPA anticipated that each plant will operate one front-end loader if the plant is identified for impoundment savings.

5.3 BOTTOM ASH TRANSPORT WATER

EPA estimated costs associated with high recycle rate for this final rule. EPA also estimated costs for zero discharge, which reflects requirements for BA transport water from the 2015 rule. These zero discharge costs are referred to here after as baseline costs. As described in the preamble, EPA established a low utilization subcategory. Low utilization is defined as a two-year average capacity utilization of less than 10 percent. For the EGUs defined as low utilization, EPA estimated costs associated with a best management practices (BMP) plan instead of the high recycle rate technology. EPA estimated the costs associated with installing additional handling or treatment technologies that eliminate or reduce the discharge of BA transport water. EPA then compared these costs to the cost to meet the 2015 rule requirements, equivalent to the zero-discharge technology options, to estimate incremental costs and savings to the steam electric power generating industry. Table 5-7 lists the technologies EPA used as the basis for the three bottom ash technology options considered. EPA also estimated the cost savings associated with plants ceasing operation of impoundments currently used for the treatment of BA transport water (see Section 5.3.7).

SECTION 9
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EXHIBIT 3

United States Environmental Protection Agency | Office of Water Washington, DC 20460 | EPA-821-R-20-004 August 28, 2020



Regulatory Impact Analysis for Revisions to the Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category



Regulatory Impact Analysis for Revisions to the Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category

EPA-821-R-20-004

August 28, 2020

U.S. Environmental Protection Agency
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Abbreviations

ACE	Affordable Clean Energy
AEO	Annual Energy Outlook
ASCC	Alaska Systems Coordinating Council
BAT	Best available technology economically achievable
BCA	Benefit and Cost Analysis
BEA	U.S. Bureau of Economic Analysis
BLS	U.S. Bureau of Labor Statistics
BMP	Best management practice
BPJ	Best professional judgment
BPT	Best practicable control technology currently available
BSER	Best system of emissions reduction
CAA	Clean Air Act
CCI	Construction cost index
CCR	Coal combustion residuals
CFR	Code of Federal Regulations
CP	Chemical precipitation
CPP	Clean Power Plan
CSAPR	Cross-State Air Pollution Rule
CWA	Clean Water Act
DOE	Department of Energy
EA	Environmental Assessment
ECI	Employment Cost Index
EGU	Electricity generating units
EIA	Energy Information Administration
EJ	Environmental justice
ELGs	Effluent limitations guidelines and standards
EO	Executive Order
EPA	U.S. Environmental Protection Agency
FERC	Federal Energy Regulatory Commission
FGD	Flue gas desulfurization
FOM	Fixed O&M
FR	Federal Register
FRCC	Florida Reliability Coordinating Council
GDP	Gross domestic product
GW	Gigawatt
GWh	Gigawatt-hour
HICC	Hawaii Coordinating Council
HRI	Heat rate improvement
HRR	High recycle rate
HRTR	High Hydraulic Residence Time Reduction
IPM	Integrated Planning Model
kWh	Kilowatt-hour

LRTR	Low Hydraulic Residence Time Reduction
MATS	Mercury and Air Toxics Standards
Mcf	Million cubic feet
MDS	Mechanical drag system
MRO	Midwest Reliability Organization
MT	Million short tons
MW	Megawatt
MWh	Megawatt-hour
NAICS	North American Industry Classification System
NERC	North American Electric Reliability Corporation
NPCC	Northeast Power Coordinating Council
NPDES	National Pollutant Discharge Elimination System
NSPS	New Source Performance Standards
NTTAA	National Technology Transfer and Advancement Act
O&M	Operation and maintenance
OMB	Office of Management and Budget
POTW	Publicly owned treatment works
PRA	Paperwork Reduction Act
PSES	Pretreatment Standards for Existing Sources
PSNS	Pretreatment Standards for New Sources
QA	Quality assurance
QC	Quality control
RCRA	Resource Recovery and Conservation Act
RIA	Regulatory Impact Analysis
RFA	Regulatory Flexibility Act
RFC	Reliability First Corporation
RGGI	Regional Greenhouse Gas Initiative
SBA	Small Business Administration
SBREFA	Small Business Regulatory Enforcement Fairness Act
SERC	SERC Reliability Corporation
SISNOSE	Significant impact on a substantial number of small entities
SPP	Southwest Power Pool
TDD	Technical Development Document
TRE	Texas Regional Reliability Entity
TWF	Toxic weighting factor
TWh	Terawatt-hour
TWPE	Toxic weighted pound equivalent
UMRA	Unfunded Mandates Reform Act
USC	United States Code
VIP	Voluntary Incentive Program
VOM	Variable O&M
WECC	Western Energy Electricity Coordinating Council

3 Compliance Costs

In developing the final rule, EPA updated the proposed rule costs and economic impacts for regulatory options A through C described in Table 1-1. Key inputs for these analyses include the estimated costs to steam electric power plants (and their business, government, or non-profit owners) for implementing control technologies upon which the final BAT limitations and pretreatment standards are based,[15] and to the state and federal government for administering this rule. This chapter summarizes EPA estimates of the incremental compliance costs attributable to the final rule, based on a comparison of steam electric industry compliance costs for the baseline and regulatory options.[16] EPA determined that state and federal governments would not incur significant incremental administrative costs.[17]

EPA applied the same methodology used to analyze the 2015 rule and 2019 proposal to calculate industry-level annualized compliance costs. See Chapter 3 of the respective RIA documents for details (U.S. EPA, 2015c, 2019a). EPA did not update its evaluation of Option D (Option 1 described in the proposal), but is presenting results from the 2019 analysis where appropriate to provide context to the discussion of results for Options A, B, and C.

The *Supplemental TDD* describes the control technologies and their respective wastewater treatment performance in greater detail (U.S. EPA, 2020e). The *Supplemental TDD* also describes how EPA estimated plant-specific capital and operation and maintenance (O&M) costs for six technologies, as well as for BMP plans.

3.1 Analysis Approach and Inputs

EPA updated estimated costs to plants for meeting the limitations of the regulatory options. There are four principal steps to compliance cost development, the last two of which are the focus of the discussion below:

1. Determining the set of plants potentially implementing compliance technologies for each regulatory option. See *Supplemental TDD* for details.

2. Developing plant-level costs for each wastestream and technology option. See *Supplemental TDD* for details.

3. Estimating the year when each steam electric power plant would be required to meet new BAT effluent limits and pretreatment standards, accounting for the regulatory option specifications and any planned unit retirements or units ceasing the combustion of coal. This schedule supports

[15] Dischargers are not required to use the technologies specified as the basis for the rule. They are free to identify other perhaps less expensive technologies as long as they meet the BAT limitations and pretreatment standards in the rule.

[16] The regulatory options would apply only to existing sources, with new sources continuing to be subject to the New Source Performance Standards (NSPS) and Pretreatment Standards for New Sources (PSNS) promulgated in the 2015 rule.

[17] EPA estimates that the final rule will not impose significant additional administrative cost to the State and federal governments. See *Section 10.8, Paperwork Reduction Act of 1995,* for additional discussion, including related to additional requirements for permitting authorities to use best professional judgement (BPJ) in making bottom ash purge water volume and technology determinations.

analysis of the timing of compliance costs and benefits for analyses discussed in this document and in the *BCA*.

4. Estimating *total* industry costs for all plants in the steam electric universe for each of the regulatory options.

An additional step involves comparing the total industry costs from Step 4 to total industry costs similarly obtained for the baseline to estimate the incremental costs attributable to each regulatory option.

EPA reports costs in 2018 dollars and discounts the costs to 2020.[18]

3.1.1 Plant-Specific Costs Approach

As detailed in the *Supplemental TDD*, EPA developed costs for steam electric power plants to implement treatment technologies or process changes to control the wastestreams addressed by the regulatory options (*i.e.*, bottom ash transport water and FGD wastewater).

EPA assessed the operations and treatment system components currently in place at a given unit (or required to be in place to comply with other existing environmental regulations), identified equipment and process changes that plants would likely make to meet the 2015 rule (for baseline) and each of the regulatory options presented in Table 1-1, and estimated the cost to implement those changes. Because the 2015 rule[19] is the baseline for analysis but plants were not required to comply with the 2015 rule limitations for the two wastestreams addressed in this rule until November 2020, EPA first developed costs to meet the 2015 rule based on current plant equipment, processes, and treatment technologies. EPA then developed similar costs for the regulatory options. The difference between the baseline and regulatory option cost estimates reflect the incremental costs attributable to the regulatory options. Plants that do not generate a wastewater or that employ technologies which would already meet the given limitations or standards do not incur costs. For several regulatory options, including the final rule, the costs of meeting the BAT imitations or pretreatment standards are less than those estimated for meeting the 2015 rule, and the options therefore result in cost savings to the industry as compared to the baseline.

3.1.2 Plant-Level Costs

Following the approach used for the analysis of the 2015 rule and 2019 proposal (U.S. EPA, 2015c, 2019a), EPA estimated compliance costs for all existing steam electric power plants, estimated to be a total 914 plants for the point source category overall. EPA assessed that only a fraction of the universe of steam electric power plants – 294 plants – have the potential to incur any costs under the regulatory options based on their wastestreams. Furthermore, out of these plants, only a subset would incur non-zero costs under any of the scenarios analyzed for the regulatory options, based on existing control technologies: 110 plants under the baseline and up to 86 plants under regulatory options A through C. The *Supplemental TDD* provides additional details on this analysis.

[18] In its analysis of the 2015 rule, EPA presented costs in 2013 dollars and discounted these compliance costs to 2015 (see U.S. EPA, 2015c).

[19] This includes the September 2017 postponement rule which delayed the earliest compliance date for the ELGs applicable to FGD wastewater and bottom ash transport water.

The major components of technology costs are:

- *Capital costs* include the cost of compliance technology equipment, installation, site preparation, construction, and other upfront, non-annually recurring outlays associated with compliance with the regulatory options. EPA assumes that plants incur all capital costs in the year when their permit is renewed to incorporate the new limitations or standards (see *Technology Implementation Years* below). As explained in the 2015 TDD and Supplemental TDD, all compliance technologies are assumed to have a useful life of 20 years. While the analysis uses as an input the cost to plant owners to purchase equipment, EPA also conducted a sensitivity analysis that compares costs of leasing as opposed to purchasing equipment. This analysis suggests that leasing may be more expensive for short cost recovery periods, such as when the unit may operate over a shorter period than 20 years, but the results are highly uncertain. See the memorandum entitled "*Cost to Lease Flue Gas Desulfurization Wastewater Treatment*" (DCN SE08633 in the rule docket).

- *Initial one-time costs* (apart from capital costs, above), if applicable, consist of a one-time cost to make the bottom ash system closed loop to eliminate discharges of bottom ash transport water (*e.g.*, under the baseline) or a one-time cost to develop a Best Management Practice (BMP) plan to recycle bottom ash transport water (*e.g.*, under Option A). Steam electric power plants are estimated to incur these costs only once during their technology implementation year.

- *Annual fixed O&M costs*, if applicable, include regular *annual* monitoring. Plants incur these costs each year.

- *Annual variable O&M costs*, if applicable, include annual operating labor, maintenance labor and materials, electricity required to operate wastewater treatment systems, chemicals, combustion residual waste transport and disposal operation and maintenance, and savings from not operating and maintaining ash/FGD pond systems. Plants incur these costs each year.

In addition to these initial one-time and annual outlays, certain other costs are estimated to be incurred on a non-annual, periodic basis:

- *3-Yr fixed O&M costs*, if applicable, include mechanical drag system (MDS) chain replacement costs that plants are estimated to incur every three years, beginning three years after the technology implementation year.

- *5-Yr fixed O&M costs*, if applicable, include remote MDS chain replacement costs that plants are estimated to incur every five years, beginning five years after the technology implementation year.

- *6-Yr fixed O&M costs*, if applicable, include mercury analyzer operations and maintenance costs that plants are estimated to incur every six years, beginning in the technology implementation year.

- *10-Yr fixed O&M costs*, if applicable, include savings from not needing to periodically maintain ash/FGD pond systems. Plants are estimated to incur savings every 10 years from not needing to

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purchase earthmoving equipment for the pond systems, beginning 5 years after the technology implementation year.

Based on information in the record concerning the normal downtime of electricity generating units, EPA estimated that plants would be able to coordinate the implementation of wastewater treatment systems during already scheduled downtime.

3.1.3 Technology Implementation Years

The years in which individual steam electric power plants are estimated to implement control technologies are an important input to the time profile of costs that plants would incur due to the regulatory options. This profile is used to estimate the change in the annualized costs to the steam electric industry and society associated with the regulatory options as compared to the baseline.

EPA envisions that each plant to which the regulatory options would apply would study available technologies and operational measures, and subsequently install, incorporate, and optimize the technology most appropriate for each site. As part of its consideration of the technological availability and economic achievability of the BAT limitations and pretreatment standards in the rule and following the approach the Agency used for the 2015 rule and 2019 proposal, EPA considered the magnitude and complexity of process changes and new equipment installations that would be required at plants to meet the requirements of the regulatory options in determining the time plant owners may need to comply with any revised limitations or pretreatment standards. See discussion in the *Supplemental TDD* (U.S. EPA, 2019b).

As described in greater detail in the final rule preamble, EPA is establishing deadlines for meeting the BAT limitations and pretreatment standards. In analyzing the regulatory options, EPA identified and included in the analysis the differences in deadlines across the options, wastestreams, type of discharge (direct or indirect), and whether a plant participates in the Voluntary Incentive Program (VIP). Table 3-1 summarizes the relevant deadlines for each regulatory option, based on the wastestream and plant category.

Table 3-1: Compliance Deadlines for the Baseline and Regulatory Options

Wastestream	Plant Subset	Compliance "No Later Than" Deadline (Technology Basis)[b]				
		Baseline	Option D[c]	Option A	Option B	Option C
Bottom Ash Transport Water	All[a] plants unless otherwise qualified	2023 (Dry handling)	2023 (CP)	2025 (HRR)	2025 (HRR)	2025 (HRR)
	Low utilization boilers	Not applicable	Not applicable	2023 (BMP)	Not applicable	Not applicable
	Generating units ceasing combustion of coal		Not applicable	2028		

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Table 3-1: Compliance Deadlines for the Baseline and Regulatory Options

Wastestream	Plant Subset	Compliance "No Later Than" Deadline (Technology Basis)[b]				
		Baseline	Option D[c]	Option A	Option B	Option C
FGD Wastewater	All[a] plants unless otherwise qualified	2023 (CP + HRTR)	2023 (CP)	2025 (CP + LRTR)	2025 (CP + LRTR)	2028 (Membrane)
	Low utilization boilers	Not applicable	Not applicable	2023 (CP)	Not applicable	Not applicable
	High FGD flow facilities					
	VIP	2023 (CP + Evaporation)	2028 (Membranes)	2028 (Membranes)	2028 (Membranes)	Not applicable
	Generating units ceasing combustion of coal	Not applicable	Not applicable	2028	Not applicable	Not applicable

CP = Chemical precipitation; LRTR = Low Residence Time Reduction; HRTR = High Residence Time Reduction; BMP = Best Management Practices; HRR = High Recycle Rate.

a. For units with nameplate capacity greater than 50 MW

b. The compliance "no later than" deadline is 2023 for indirect discharges across all options.

c. Option D corresponds to proposed Option 1.

The timing decision represents when the technologies are available, accounting for the need to provide sufficient time for plant owners to raise capital, plan and design systems, procure equipment, and construct and then test systems, recognizing that some plant owners have already met or taken steps to meet the ELGs EPA finalized in 2015. Moreover, specifying compliance deadlines in the future enables plants to take advantage of planned shutdown or maintenance periods to install new pollution control technologies. This allows for the coordination of generating unit outages in order to maintain grid reliability and prevent any potential impacts on electricity availability caused by forced outages. It is not possible to predict, for each plant, exactly the date the final rule will be incorporated into permits, for purposes of determining exactly when plants will incur costs to meet the new requirements. Similar to the approach used in analyzing the 2015 rule and 2019 proposal, EPA generally expects plants to meet the new BAT limitations and pretreatment standards in a somewhat staggered fashion, given that (1) for some regulatory options, the permitting authority determines the date after considering certain specified factors, and (2) all permits are not re-issued at the same time due to their 5-year permit term. Thus, for the cost and economic impact analyses, EPA assumed implementation over a 3- to 5-year period preceding any established "no later than" date.[20]

For the purpose of this analysis, EPA accounted for the timing of announced unit retirements or repowerings in determining the compliance year for the plant. Specifically, in cases where the announced retirement occurs after the default compliance year based on the permit renewal cycle but before the applicable final rule compliance deadline, EPA assumed that permit authorities would set the "no later

[20] For the purpose of the analysis, EPA assigned an estimated compliance year to each of the 294 steam electric power plants analyzed for the final rule based on each plant's estimated NPDES permit renewal year and, similar to the approach used for the 2015 rule and 2019 proposal, the assumption that all permits will be renewed promptly (no administrative continuances). EPA projected future NPDES permit years by assuming permits are renewed every 5 years, *i.e.*, a permit expiring in 2021 would be renewed in 2026 and 2031.

than" compliance date to correspond to the retirement date. In these cases, the plant would incur no incremental costs to comply with the final rule.

EPA also accounted for announced unit retirements or repowerings in the social cost analysis, which is discussed and detailed in Chapter 12 of the BCA. Specifically, EPA assumed zero O&M costs in all years following a unit's retirement or repowering.

3.1.4 Total Compliance Costs

EPA used the following methodology and assumptions to aggregate compliance cost components, described in the preceding sections, and develop total plant compliance costs for regulatory options A through C:

- EPA estimated compliance costs (including zero costs) for each of the 294 steam electric power plants with the relevant wastestreams, *i.e.*, coal-fired power plants (see *Supplemental TDD* for details). All other plants covered by the steam electric power point source category are estimated to incur zero costs.

- EPA restated compliance costs estimated in the preceding step, accounting for the specific years in which each plant is assumed to undertake compliance-related activities and in 2018 dollars, using the Construction Cost Index (CCI) from McGraw Hill Construction (2020), the Employment Cost Index (ECI) published by the Bureau of Labor Statistics (BLS) (2020), and the Gross Domestic Product (GDP) deflator index published by the U.S. Bureau of Economic Analysis (BEA) (2019).[21]

- EPA discounted all cost values to 2020, using a rate of 7 percent.[22]

- EPA annualized one-time costs and costs recurring on other than an annual basis over a specific useful life, implementation, and/or event recurrence period, using a rate of 7 percent:[22]

[21] Specifically, EPA brought all compliance costs to an estimated technology implementation year using the CCI from McGraw Hill Construction (2020) or the ECI from the Bureau of Labor Statistics (2020), depending on the cost component. The Agency used the average of the year-to-year changes in the CCI (or ECI) over the most recent ten-year reporting period to bring these values to an estimated compliance year. Because the CCI (or ECI) is a nominal cost adjustment index, the resulting technology cost values are as of the compliance year and in the dollars of the technology implementation year. To restate compliance cost values in 2018 dollars, the Agency deflated the nominal dollar values to 2018 using the average of the year-to-year changes in the GDP deflator index published by the BEA over the most recent ten-year reporting period. As a result, all dollar values reported in this analysis are in constant dollars of the year 2018.

[22] The rate of 7 percent is used in the cost impact analysis as an estimate of the private opportunity cost of capital. For the social cost analysis presented in Chapter 12 of the BCA, EPA uses both 3 percent and 7 percent discount rates. The 3 percent discount rate reflects society's valuation of differences in the timing of consumption; the 7 percent discount rate reflects the opportunity cost of capital to society. In Circular A-4, the Office of Management and Budget (OMB) recommends that 3 percent be used when a regulation affects private consumption, and 7 percent in evaluating a regulation that will mainly displace or alter the use of capital in the private sector (U.S. OMB, 2003; updated 2009). The same discount rates are used for both benefits and costs in the BCA.

  - Capital costs of each compliance technology: 20 years
  - Initial one-time costs: 20 years[23]
  - 3-Yr O&M: 3 years
  - 5-Yr O&M: 5 years
  - 6-Yr O&M: 6 years
  - 10-Yr O&M: 10 years

- EPA added annualized capital, initial one-time costs, and annualized O&M costs recurring on other than an annual basis to the annual O&M costs to derive total annualized compliance costs.

EPA accounted for the timing of announced plant retirements in determining the useful life over which to annualize recurring costs. In cases where a plant's announced retirement year occurs after the first instance of a recurring O&M cost but before the second instance, EPA adjusted the useful life of that cost category to be the number of years that the plant is expected to operate after the first instance.

EPA did not adjust the annualization of capital costs to reflect plant-specific considerations. EPA annualized capital costs over 20 years but recognizes that some plants may retire units sooner than the 20-year life of the equipment. EPA determined the 20-year annualization period to be reasonable for this analysis because some regulators may allow utilities to recover the value of undepreciated assets in their rate base on a case-by-case basis. Additionally, actual capital costs may be less than estimated by EPA in some cases should the plant owner elect to lease rather than purchase equipment, as discussed in a sensitivity analysis summarized in the memorandum entitled "*Cost to Lease Flue Gas Desulfurization Wastewater Treatment*" (DCN SE08633 in the rule docket).

For the assessment of compliance costs to steam electric power plants, EPA considered costs on both a pre-tax and after-tax basis. Pre-tax costs provide insight on the total expenditures as initially incurred by the plants. After-tax costs are a more meaningful measure of compliance impact on privately owned for-profit plants, and incorporate approximate capital depreciation and other relevant tax treatments in the analysis. EPA calculated the after-tax value of compliance costs by applying combined federal and State tax rates to the pre-tax cost values for privately owned for-profit plants.[24] For this adjustment, EPA used State corporate rates from the Federation of Tax Administrators (2019) combined with a 21 percent federal corporate tax rate.[25] As discussed in the relevant sections of this document, EPA uses either pre- or after-tax compliance costs in different analyses, depending on the concept appropriate to each analysis (*e.g.*, cost-to-revenue screening-level analyses are conducted using after-tax compliance costs). Note that for social costs, which are discussed and detailed in Chapter 12 of the BCA, EPA uses pre-tax costs.[26]

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23 EPA annualized these non-equipment outlays over 20 years to match the estimated performance life of compliance technology components.

24 Government-owned entities and cooperatives are not subject to income taxes. To distinguish among the government-owned, privately owned, and cooperative ownership categories, EPA relied on the Steam Electric Survey and additional research on parent entities using publicly available information. See *Chapter 4: Economic Impact Screening Analyses* for further discussion of these determinations.

25 This federal tax rate reflects the Tax Cuts and Jobs Act of 2017 which changed the top corporate tax rate from 35 percent to one flat rate of 21 percent after January 1, 2018.

26 As described in Chapter 12 of the BCA, EPA used costs incurred by steam electric power plants for the labor, equipment, material, and other economic resources needed to comply with the regulatory options as a proxy for social

3.1.5 Voluntary Incentive Program

As described in the proposal, under the VIP component of regulatory options A and B, plants that discharge directly to waters can voluntarily commit to meeting more stringent FGD limitations based on a membrane filtration treatment technology instead of limits based on CP+LRTR technology. VIP participants have more time – until 2028 – to meet the lower limits based on membrane filtration, as compared to having to meet the limits based on CP+LRTR by 2025.

Because participation in the VIP is voluntary, the set of plants participating in the program is uncertain. For the purpose of the economic analysis, EPA estimated VIP participants by comparing the estimated costs of the two technologies for each facility estimated to incur compliance costs and assuming that a plant owner would select the less costly of the two. Specifically, the Agency compared the annualized and discounted cost of implementing CP+LRTR between 2021 and 2025 (based on the plant-specific schedule described in Section 3.1.3) or implementing membrane filtration in 2028. Based on this analysis, EPA estimated that 8 plants may choose to participate in the VIP under Option A (final rule) and 13 plants may choose to participate in the VIP under Option B. For these plants, EPA retained the membrane filtration costs for estimating economics impacts in this document and for the benefit cost analysis in Chapter 12 of the BCA.

3.2 Key Findings for Regulatory Options

3.2.1 Estimated Industry-level Total Compliance Costs

Table 3-2 presents compliance cost estimates for the baseline and regulatory options, Table 3-3 summarizes *incremental* costs for each option as compared to the baseline, and Table 3-4 shows the breakout of incremental total compliance costs for each option by wastestream. Table 3-3 and Table 3-4 include incremental costs previously estimated for Option D (Option 1 in U.S. EPA, 2019a) as context to the estimates for Options A, B, and C.

EPA estimates that, on a *pre-tax* basis, steam electric power plants would incur annualized costs of meeting the regulatory options ranging from $203 million under Option A to $359 million under Option C compared to pre-tax costs of $378 million for the baseline. Thus, all three options reanalyzed provide cost savings when compared to the 2015 rule, with pre-tax savings ranging from $20 million to $175 million (cost savings are shown as negative values in Table 3-3 and Table 3-4). On an *after-tax* basis, the total compliance costs range from $169 million to $295 million, and cost savings range from $14 million to $140 million, depending on the option. On both the pre-and post-tax bases, compliance costs are lowest, and savings greatest, for Option A (the final rule).

All three regulatory options reanalyzed yield annualized costs savings for the bottom ash transport water wastestream. The greatest savings are achieved under Option A ($80 million after-tax), due to subcategorization of low utilization units under Option A. Options A, B, and D provide annualized cost

costs. The social cost analysis considers costs on an as-incurred, year-by-year basis. In the social cost analysis, EPA assumed that the market prices for labor, equipment, material, and other compliance resources represent the opportunity costs to society for use of those resources in regulatory compliance. EPA further assumed that the regulatory options do not affect the aggregate quantity of electricity that would be sold to consumers and, thus, that the rule's social cost would include no changes in consumer and producer surplus *from changes in electricity sales* by the electricity industry in aggregate. Given the small impact of the regulatory options on electricity production cost for the total industry (see *Chapter 5*), this is a reasonable assumption.

savings for FGD wastewater. The greatest savings for FGD wastewater are achieved under Option A ($60 million after-tax) whereas Option C results in higher costs for FGD wastewater ($49 million on an annualized, after-tax basis), when compared to the baseline.

Table 3-2: Estimated Total Annualized Compliance Costs (in millions, 2018$, at 2020)

Regulatory Option	Pre-Tax Compliance Costs				After-Tax Compliance Costs			
	Capital Technology	Other Initial One-Time	Total O&M	Total	Capital Technology	Other Initial One-Time	Total O&M	Total
Baseline	$208	$0	$170	$378	$170	$0	$139	$310
Option D[a]	*$163*	*$0*	*$114*	*$277*	*$132*	*$0*	*$94*	*$226*
Option A	$102	$0	$102	$203	$84	$0	$85	$169
Option B	$116	$0	$119	$235	$96	$0	$99	$195
Option C	$162	$0	$196	$359	$134	$0	$162	$295

a. Option D corresponds to the proposed Option 1. EPA did not reanalyze this option for the final rule. All results shown for Option D are based on the 2019 analysis, as detailed in the 2019 RIA (U.S. EPA, 2019a). As such, the values do not reflect changes in the baseline, plant universe, and other analytical inputs for the analysis of Options A, B, and C.

Source: U.S. EPA Analysis, 2020

Table 3-3: Estimated Incremental Annualized Compliance Costs (in millions, 2018$, at 2020)

Regulatory Option	Pre-Tax Incremental Costs				After-Tax Incremental Costs			
	Net Capital Technology	Net Other Initial One-Time[a]	Net Total O&M	Net Total Costs	Net Capital Technology	Net Other Initial One-Time[a]	Net Total O&M	Net Total Costs
Option D[a]	*-$117*	*$0*	*-$48*	*-$166*	*-$97*	*$0*	*-$40*	*-$137*
Option A	-$107	$0	-$69	-$175	-$86	$0	-$54	-$140
Option B	-$92	$0	-$51	-$143	-$74	$0	-$40	-$115
Option C	-$46	$0	$26	-$20	-$37	$0	$23	-$14

a. Option D corresponds to the proposed Option 1. EPA did not reanalyze this option for the final rule. All results shown for Option D are based on the 2019 analysis, as detailed in the 2019 RIA (U.S. EPA, 2019a). As such, the values do not reflect changes in the baseline, plant universe, and other analytical inputs for the analysis of Options A, B, and C.

Source: U.S. EPA Analysis, 2019, 2020

Table 3-4: Estimated Incremental Annualized Compliance Costs, by Wastestream (in millions, 2018$, at 2020)

Regulatory Option	Pre-Tax Incremental Costs			After-Tax Incremental Costs		
	Bottom Ash Transport Water	FGD Wastewater	Net Total Costs	Bottom Ash Transport Water	FGD Wastewater	Net Total Costs
Option D[a]	*-$43*	*-$123*	*-$166*	*-$34*	*-$103*	*-$137*
Option A	-$104	-$71	-$175	-$80	-$60	-$140
Option B	-$81	-$62	-$143	-$63	-$51	-$115
Option C	-$81	$62	-$20	-$63	$49	-$14

a. Option D corresponds to the proposed Option 1. EPA did not reanalyze this option for the final rule. All results shown for Option D are based on the 2019 analysis, as detailed in the 2019 RIA (U.S. EPA, 2019a). As such, the values do not reflect changes in the baseline, plant universe, and other analytical inputs for the analysis of Options A, B, and C.

Source: U.S. EPA Analysis, 2019, 2020

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3.2.2 Estimated Regional Distribution of Incremental Compliance Costs

Table 3-5 reports incremental costs for each regulatory option at the level of a North American Electric Reliability Corporation (NERC) region as compared to baseline (see Table 2-5).[27] As explained in Chapter 2 (Overview of the Steam Electric Industry), because of differences in operating characteristics of steam electric power plants across NERC regions, as well as differences in the economic and electric power system regulatory circumstances of the NERC regions themselves, the regulatory options may affect costs, profitability, electricity prices, and other impact measures differently across NERC regions.

Annualized after-tax compliance costs are highest in the SERC and RFC regions for all reanalyzed regulatory options (A through C) and, as shown in Table 3-5, these regions also see the greatest incremental cost savings under option A and B. RFC also has the largest cost savings under Option C. For corresponding result for Option D, see the 2019 RIA (U.S. EPA, 2019a).

Table 3-5: Estimated Annualized Incremental Compliance Costs by NERC Region (in millions, 2018$, at 2020)

	Pre-Tax Incremental Compliance Costs				After-Tax Incremental Compliance Costs			
NERC Region[a]	Capital Technology	Other Initial One-Time	Total O&M	Total	Capital Technology	Other Initial One-Time	Total O&M	Total
				Option D[b]				
FRCC	*-$6*	*$0*	*-$2*	*-$9*	*-$5*	*$0*	*-$2*	*-$7*
MRO	*-$3*	*$0*	*-$1*	*-$4*	*-$3*	*$0*	*-$1*	*-$4*
NPCC	*-$1*	*$0*	*-$1*	*-$2*	*-$1*	*$0*	*-$1*	*-$1*
RFC	*-$41*	*$0*	*-$19*	*-$60*	*-$31*	*$0*	*-$14*	*-$46*
SERC	*-$60*	*$0*	*-$22*	*-$82*	*-$52*	*$0*	*-$20*	*-$72*
SPP	*-$4*	*$0*	*-$2*	*-$6*	*-$3*	*$0*	*-$1*	*-$5*
TRE	*-$2*	*$0*	*-$1*	*-$2*	*-$1*	*$0*	*-$1*	*-$2*
WECC	*-$0*	*$0*	*-$0*	*-$0*	*-$0*	*$0*	*-$0*	*-$0*
Total	***-$117***	***$0***	***-$48***	***-$166***	***-$97***	***$0***	***-$40***	***-$137***
				Option A				
FRCC	-$5	$0	$0	-$5	-$4	$0	$0	-$4
MRO	-$5	$0	-$4	-$9	-$4	$0	-$3	-$7
NPCC	-$1	$0	-$2	-$3	-$1	$0	-$1	-$2
RFC	-$37	$0	-$27	-$63	-$27	$0	-$19	-$47
SERC	-$45	$0	-$22	-$67	-$39	$0	-$18	-$58
SPP	-$7	$0	-$5	-$13	-$6	$0	-$4	-$10
TRE	-$2	$0	-$1	-$3	-$2	$0	-$1	-$3
WECC	-$5	$0	-$7	-$13	-$4	$0	-$6	-$10
Total	**-$107**	**$0**	**-$69**	**-$175**	**-$86**	**$0**	**-$54**	**-$140**
				Option B				
FRCC	-$4	$0	$0	-$4	-$3	$0	$0	-$3
MRO	-$3	$0	-$2	-$5	-$3	$0	-$2	-$5
NPCC	$0	$0	$0	$0	$0	$0	$0	$0
RFC	-$32	$0	-$22	-$54	-$24	$0	-$17	-$41
SERC	-$42	$0	-$18	-$59	-$35	$0	-$15	-$50
SPP	-$5	$0	-$3	-$8	-$4	$0	-$2	-$7

[27] No steam electric power plant is estimated to incur compliance costs in the ASCC and HICC NERC regions and these two regions are therefore omitted from the presentation of results.

Table 3-5: Estimated Annualized Incremental Compliance Costs by NERC Region (in millions, 2018$, at 2020)

NERC Region[a]	Pre-Tax Incremental Compliance Costs				After-Tax Incremental Compliance Costs			
	Capital Technology	Other Initial One-Time	Total O&M	Total	Capital Technology	Other Initial One-Time	Total O&M	Total
TRE	-$2	$0	-$1	-$3	-$2	$0	-$1	-$3
WECC	-$3	$0	-$5	-$8	-$3	$0	-$4	-$6
Total	**-$92**	**$0**	**-$51**	**-$143**	**-$74**	**$0**	**-$40**	**-$115**
Option C								
FRCC	$0	$0	$5	$5	$0	$0	$4	$4
MRO	-$3	$0	-$2	-$5	-$3	$0	-$2	-$4
NPCC	$0	$0	$0	$0	$0	$0	$0	$0
RFC	-$22	$0	$5	-$17	-$17	$0	$4	-$12
SERC	-$11	$0	$25	$15	-$10	$0	$22	$12
SPP	-$4	$0	-$1	-$5	-$3	$0	-$1	-$4
TRE	-$2	$0	-$1	-$3	-$1	$0	-$1	-$2
WECC	-$3	$0	-$5	-$8	-$3	$0	-$4	-$6
Total	**-$46**	**$0**	**$26**	**-$20**	**-$37**	**$0**	**$23**	**-$14**

a. EPA estimated zero ELG compliance costs in the ASCC and HICC regions. These two regions are omitted from the table presentation. This omission does not affect totals.

b. Option D corresponds to the proposed Option 1. EPA did not reanalyze this option for the final rule. All results shown for Option D are based on the 2019 analysis, as detailed in the 2019 RIA (U.S. EPA, 2019a). As such, the values do not reflect changes in the baseline, plant universe, and other analytical inputs for the analysis of Options A, B, and C.

Source: U.S. EPA Analysis, 2020

3.3 Key Uncertainties and Limitations

Economic analyses are not perfect predictions and thus, like all such analyses, this analysis has some uncertainties and limitations.

- The compliance costs used in this analysis for the regulatory options reflect unit retirements, conversions, and repowerings announced through January 2020 and scheduled to occur by the end of 2028. For details, see memorandum entitled "*Changes to Industry Profile for Coal-Fired Generating Units for the Steam Electric Effluent Guidelines Final Rule*" (DCN SE08688 in the rule docket). To the extent that actual unit retirements, conversions, and repowerings at steam electric power plants differ from announced changes, estimated annualized compliance costs of the regulatory options may differ from actual costs.

- EPA assumed that the equipment installed to meet any new limitations could reasonably be estimated to operate for 20 years or more, based on a review of reported performance characteristics of the equipment components. EPA thus used 20 years as the basis for the cost and economic impact analyses that account for the estimated operating life of compliance technology. To the extent that the actual service life is longer or shorter than 20 years, costs presented on annual equivalent basis would be over- or under-stated.

- Annualized compliance costs depend on the assumed technology implementation year. For the purpose of the cost and economic impact analyses, EPA determined years in which technology implementation would reasonably be estimated to occur across the universe of steam electric

power plants, based on plant-specific information about existing NPDES permits and extrapolating future permit issuance dates assuming permits are renewed every five years. To the extent that compliance costs are incurred in an earlier or later year, the annualized values presented in this section may under or overstate the annualized total costs of the regulatory options.

- EPA estimated VIP participants for options A and B based on the lowest cost technology on an annualized and discounted basis, but plant owners may consider other factors in deciding whether to participate in the VIP so actual participation may be higher or lower than projected.

- As described in Section 2.2.2, EPA accounted for the 2015 final CCR rule and incremental effects of the final CCR Part A rule in its analysis of the final rule. EPA did not account for the proposed CCR Part B rule in its analysis of this final ELG rule. Because the proposed CCR Part B rule is a deregulatory action, EPA estimates that cost savings of this final ELG rule are underestimated. For more details on the effects of the proposed CCR Part B rule on the total costs of the final rule, see the memorandum entitled "*Assessment of the economic impacts of the final revised Steam Electric ELGs relative to an alternative baseline including the CCR Part B Rule"* (DCN SE09360 in the rule docket).

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A Summary of Changes to Costs and Economic Impact Analysis

Table A-1 summarizes the principal methodological changes EPA made to analyses of the costs and economic impacts of the final ELG reconsideration rule as compared to the proposed ELG reconsideration rule described in the 2019 RIA (U.S. EPA, 2019a).

Table A-1: Changes to Costs and Economic Impacts Analysis Since Proposal

Cost or Impact Category	Analysis Component	Cost or Impact Category
General inputs for screening-level analyses	Generation, plant revenue, and estimated electricity prices using EIA-861 and EIA-923 databases; six-year (2011-2016) average values	Updated with data from more current EIA-861 and EIA-923 databases to use more recent six-year [2013-2018] average values
	Generating capacity from 2016 EIA-860	Updated using 2018 EIA-860
	NERC regions from 2016 EIA-860	Updated using 2017 EIA-860
	Electricity revenue, sales, and number of consumers by consumer class (residential, industrial, commercial, and transportation) for ASCC and HICC regions from EIA-861 for [2016]	Updated to use data from EIA-861 for [2018]
	Electricity revenue, sales, and number of consumers by consumer class (residential, industrial, commercial, and transportation) for NERC regions other than ASCC and HICC regions from [2018] AEO projections	Updated using [2019] AEO projections
Industry profile	Total count of plants (951 plants)	Updated universe of 914 plants reflects information on actual, planned, and announced unit retirements through the end of 2028.
	Industry data (*i.e.*, capacity, generation, number of plants, etc.) from 2016 EIA databases	Updated using 2018 EIA databases
Screening-level plant impacts	Cost-to-revenue impact indicators (1% and 3%) based on 6-year (2011-2016) average values of electricity generation and electricity prices (to estimate plant-level revenue)	Updated to use average electricity generation and electricity prices for [2013-2018]
Market-level impacts (IPM)	The Baseline includes existing regulatory requirements as of December 2019 and representation of the 2015 ELG based on 2018 data.	The Baseline includes existing regulatory requirements as of January 2020, plus the final CCR Part A rule and an updated representation of the 2015 ELG based on 2020 data.
Potential electricity price effects	Projected total electricity sales in [2020] from [AEO 2018]	Projected total electricity sales in [2020] from [AEO 2019]
	Electricity sales data by consumer group from [2016] EIA-860 database	Electricity sales data by consumer group from [2018] EIA-860 database
Owner-level impacts and RFA/SBREFA	Owners identified in EIA-860 [2016]	Owners identified in EIA-860 [2018]
	Small business size determination metrics [mostly publicly available sources for private entities; Census ACS 2016 for governments]	Small business size determination metrics [mostly publicly available sources for private entities; Census ACS 2017 for governments]

Table A-1: Changes to Costs and Economic Impacts Analysis Since Proposal		
Cost or Impact Category	**Analysis Component**	**Cost or Impact Category**
EO 12898: EJ	Refers to BCA Chapter 14. Qualitative discussion draws on benefits analyses. See Table 2 for details. Presents profile of population in the vicinity of steam electric power plants and selected results of the benefits analyses by income and minority status	Update profile and discussion of distributional effects to reflect exposure via drinking water

B Comparison of Incremental Costs and Pollutant Removals

This appendix describes EPA's analysis of the incremental costs and pollutant removals of the regulatory options. The information provides insight into how regulatory options compare to each other in terms of reducing toxic pollutant discharges to surface waters.

B.1 Methodology

Cost-effectiveness is defined as the incremental annualized cost of a pollution control option in an industry or industry subcategory per incremental pound equivalent of pollutant (*i.e.*, pound of pollutant adjusted for toxicity) removed by that control option. The analysis compares removals for pollutants directly regulated by the ELGs and incidentally removed along with regulated pollutants.

As described for the 2015 rule, EPA's cost-effectiveness analysis involves the following steps to generate input data and calculate the desired values (see Appendix F in U.S. EPA, 2015c):

1. Determine the pollutants considered for regulation.
2. For each pollutant, obtain relative toxic weights and POTW removal factors.
3. Define the regulatory pollution control options.
4. Calculate pollutant removals and toxic-weighted pollutant removals for each control option and for each of direct and indirect discharges. For indirect dischargers, the calculations include applying a factor that reflects the ability of a POTW or sewage treatment plant to remove pollutants prior to discharge to water. See *Supplemental TDD* (U.S. EPA, 2020e) for details.
5. Determine the total annualized compliance cost for each control option and for direct and indirect dischargers.
6. Adjust the cost obtained in step 5 to 1981 dollars.
7. Calculate the cost-effectiveness ratios for each control option and for direct and indirect dischargers.

The regulatory options analyzed for the final rule represent only a subset of the requirements contained in the ELG for the steam electric industry since they address only two of the relevant wastestreams. Accordingly, EPA did not calculate the cost-effectiveness ratios for the regulatory options since these ratios would not be comparable to cost-effectiveness values EPA estimated for the 2015 rule (see Appendix F in U.S. EPA, 2015c) or for ELGs for other point source categories. The next section provides results for steps 1 through 5, where the total annualized compliance costs calculated in step 5 are relative to the 2015 rule baseline.[73]

[73] Adjustment of costs to 1981 dollars is a convention to facilitate comparison of cost-effectiveness values across rules. Since EPA is not estimating cost-effectiveness ratios in this analysis, this adjustment was not needed.

B.2 Results

Toxic Weights of Pollutants and POTW Removal

The *Supplemental TDD* provides information on the pollutants addressed by the regulatory options (U.S. EPA, 2020e). The pollutants include several metals (*e.g.*, arsenic, mercury, selenium), various non-metal compounds (*e.g.*, chloride, fluoride, sulfate), nutrients, and conventional pollutants (*e.g.*, oil and grease, biochemical oxygen demand.)

The toxic weighted pound equivalent (TWPE) analysis involves multiplying the changes in loadings of each pollutant by a pollutant-specific toxic weighting factor (TWF) that represents the toxic effect level relative to the toxicity of copper. For indirect dischargers, the changes are multiplied by a second factor that reflects the ability of a POTW or sewage treatment plant to remove pollutants prior to discharge to waters. For TWF and POTW removal factors, see Appendix F in U.S. EPA, 2015c.

Evaluated Options

EPA updated its analyses of Options A, B, and C summarized in Table 1-1. To provide context for the results, EPA did not update, but also includes results for Option D, which the Agency previously analyzed in the 2019 proposal (see Option 1 in U.S. EPA, 2019a).

Pollutant Removals and Pound Equivalent Calculations

Table B-1, below, presents estimated annual reduction in the mass loading of pollutant anticipated from direct and indirect dischargers for each regulatory option, relative to the baseline. The toxic weighted removals account for pollutant toxicity and, for indirect dischargers, for POTW removals. The calculations do not account for the removal of pollutants that do not have TWFs, either because data are not available to set a TWF or toxicity is not the pollutant's primary environmental impact (*e.g.*, nutrients contributing to eutrophication, high BOD resulting in anoxia). Furthermore, the pound equivalent pollutant removal analysis does not address routes of potential environmental damage and human exposure, and therefore potential benefits from reducing pollutant exposure.

The incremental pollutant removals for Option D are relative to the baseline analyzed for the 2019 proposal, whereas incremental pollutant removals of Options A, B, and C are estimated relative to the revised baseline for the final rule analysis.

Annualized Compliance Costs

EPA developed costs for technology controls to address each of the wastestreams present at each steam electric power plant. The *Supplemental TDD* provides additional details on the methods used to estimate the costs of meeting the limitations and standards under the baseline and each of the regulatory options (U.S. EPA, 2020e). The method used to calculate the incremental annualized compliance costs is described in greater detail in Chapter 3, *Compliance Costs*. EPA categorized these annualized compliance costs as either direct or indirect based on the discharge associated with each wastestream at each plant. Table B-1 summarizes the annualized compliance costs of the regulatory options relative to the 2015 rule baseline, whereas Figure B-1 compares the pollutant removals and costs of the regulatory options graphically.

The incremental compliance costs for Option D were calculated relative to the baseline analyzed for the 2019 proposal, whereas incremental compliance costs of Options A, B, and C are estimated relative to the revised baseline for the final rule analysis.

Table B-1: Estimated Pollutant Removal and Costs of Regulatory Options by Discharger Category

Discharger Category	Option[a]	Total Annual TWF-Weighted Pollutant Removals (lb-eq.)		Total Annual Pre-tax Compliance Costs (million, 2018$)	
		Total[b]	Incremental[c]	Total[b]	Incremental[c]
Direct	*D[d]*	*-87,291*	*-87,291*	*-$163.1*	*-$163.1*
	A[e]	-16,415	-16,415	-$173.5	-$173.5
	B	5,630	22,045	-$142.3	$31.2
	C	472,478	466,848	-$18.4	$123.9
Indirect	*D[d]*	*-526*	*-526*	*-$2.5*	*-$2.5*
	A[e]	0	0	-$1.7	-$1.7
	B	0	0	-$0.9	$0.9
	C	4,506	4,506	-$1.1	-$0.2

a. Options are listed in increasing order of pollutant removals, relative to the baseline.

b. Total removals and costs are compared to those for the baseline.

c. Incremental removals and costs are compared to those for the next least stringent option in the order listed in the table. For direct dischargers, the incremental removals and costs under Option 1 are calculated relative to the baseline, the incremental removals and costs for Option 2 are calculated relative to those of Option 1, etc.

d. Option D corresponds to the proposed Option 1. EPA did not reanalyze this option for the final rule. All results shown for Option D are based on the 2019 analysis, as detailed in the 2019 RIA (U.S. EPA, 2019a). As such, the values do not reflect changes in the baseline, plant universe, and other analytical inputs for the analysis of Options A, B, and C.

Source: U.S. EPA Analysis, 2019, 2020

Figure B-1: Estimated Removals and Costs of the Regulatory Options, Relative to Baseline.



EXHIBIT 4

MEMORANDUM

TO: Steam Electric Rulemaking Record

FROM: Eastern Research Group, Inc.

DATE: August 31, 2020

SUBJECT: **Generating Unit-Level Costs and Loadings Estimates by Regulatory Option – DCN SE08638**

ERG is providing technical support to the U.S. Environmental Protection Agency's Office of Water, Engineering and Analysis Division (EAD) for the reconsideration of effluent limitations guidelines and standards (ELGs) for the Steam Electric Power Generating Industry. EPA, with the support of ERG, evaluated data on wastewater flow rates, treatment technology costs, and pollutant concentration data from trade associations, individual power plants, previous rulemakings, and technology vendors to estimate treatment technology costs and pollutant discharge loadings associated with the discharge of flue gas desulfurization (FGD) wastewater and bottom ash transport water. EPA estimated costs and loadings associated with installing and operating the technology options evaluated as part of the ELGs for each of these wastestreams.

The methodology for estimating these costs and loadings for each wastestream and regulatory option are presented in the *Supplemental Technical Development Document for Revisions to the Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category* (EPA-821-R-20-001). This memorandum presents the treatment technology and estimated costs and pollutant loadings for each generating unit for the regulatory options considered by EPA. The regulatory options considered by EPA are presented in Table 1.

Table 1. Main Regulatory Options

Wastestreams	Subcategory	Technology Basis for the BAT/PSES Regulatory Options			
		D[a]	A	B	C
FGD Wastewater	NA	Chemical Precipitation	Chemical Precipitation + Low Hydraulic Residence Time Biological Treatment	Chemical Precipitation + Low Hydraulic Residence Time Biological Treatment	Membrane Filtration
	High Flow FGD Plants	NS	Chemical Precipitation	NS	NS
	Low Utilization Electric Generating Units	NS	Chemical Precipitation	NS	NS
	Units Permanently Ceasing Coal Combustion by 2028	NS	Surface Impoundment	NS	NS
FGD Wastewater Voluntary Incentives Program (Direct Dischargers Only)	NA	Membrane Filtration	Membrane Filtration	Membrane Filtration	NA
Bottom Ash Transport Water	NA	High Recycle Rate Systems	High Recycle Rate Systems	High Recycle Rate Systems	High Recycle Rate Systems
	Low Utilization Electric Generating Units	NS	Surface Impoundments + BMP plan	NS	NS
	Units Permanently Ceasing Coal Combustion by 2028	NS	Surface Impoundments	NS	NS

NA: Not applicable.
NS: Not subcategorized.

Note: The table above does not present existing subcategories included in the 2015 rule as EPA did not reopen the existing subcategorization of oil-fired units or units with a nameplate capacity of 50 MW or less.

a – Regulatory Option D corresponds generally to proposed Regulatory Option 1. As described in the preamble, EPA did not update the analysis for Regulatory Option D, but rather retained the results of the proposed rule analysis for this option. See DCN SE07090 for unit-level costs and loadings estimates for this option.

The following tables present the costs and loadings estimates for the steam electric industry:

- Table 2: Unit-level treatment technology matrix for baseline and Regulatory Options A-C;
- Table 3: Unit-level costs for FGD wastewater treatment under Baseline;
- Table 4: Unit-level costs for FGD wastewater treatment under Regulatory Option A;
- Table 5: Unit-level costs for FGD wastewater treatment under Regulatory Option B;
- Table 6: Unit-level costs for FGD wastewater treatment under Regulatory Option C;
- Table 7: Unit-level costs for bottom ash transport water treatment under Baseline;

- Table 8: Unit-level costs for bottom ash transport water treatment under Regulatory Option A;
- Table 9: Unit-level costs for bottom ash transport water treatment under Regulatory Option B;
- Table 10: Unit-level costs for bottom ash transport water treatment under Regulatory Option C;
- Table 11: Unit-level total pollutant loadings for FGD wastewater under Baseline;
- Table 12: Unit-level total pollutant loadings for FGD wastewater under Regulatory Option A;
- Table 13: Unit-level total pollutant loadings for FGD wastewater under Regulatory Option B;
- Table 14: Unit-level total pollutant loadings for FGD wastewater under Regulatory Option C;
- Table 15: Unit-level total pollutant loadings for bottom ash transport water under Baseline;
- Table 16: Unit-level total pollutant loadings for bottom ash transport water under Regulatory Option A;
- Table 17: Unit-level total pollutant loadings for bottom ash transport water under Regulatory Option B;
- Table 18: Unit-level total pollutant loadings for bottom ash transport water under Regulatory Option C; and

EPA estimated potential ranges of bromide and iodine loadings. Given that most coal-fired power plants use bromide additives, total loadings are calculated as the sum of bromide maximum loading and iodine minimum loading. See the Pollutant Loadings Analysis and Supporting Documentation for the 2020 Steam Electric Supplemental Environmental Assessment (DCN SE08751) on additional details on halogen loadings estimates.

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Table 4. Generating Unit-Level Costs for FGD Wastewater Treatment under Regulatory Option A

[In pre-tax 2018 dollars]

Plant Name	Plant ID	Unit ID	Treatment Technology	Capital Cost	Annual O&M Cost	One Time Cost	Recurring Costs			
							3-Year O&M Cost	5-Year O&M Cost	6-Year O&M Cost	10-Year O&M Cost
Kingston	265	SE Unit-1	LRTR	$5,428,021	$529,426	$0	$0	$0	$10,327	($48,750)
Kingston	265	SE Unit-2	LRTR	$5,428,021	$529,426	$0	$0	$0	$10,327	($48,750)
Kingston	265	SE Unit-3	LRTR	$5,428,021	$529,426	$0	$0	$0	$10,327	($48,750)
Kingston	265	SE Unit-4	LRTR	$5,428,021	$529,426	$0	$0	$0	$10,327	($48,750)
Kingston	265	SE Unit-5	LRTR	$6,203,453	$605,058	$0	$0	$0	$11,803	($55,714)
Kingston	265	SE Unit-6	LRTR	$6,203,453	$605,058	$0	$0	$0	$11,803	($55,714)
Kingston	265	SE Unit-7	LRTR	$6,203,453	$605,058	$0	$0	$0	$11,803	($55,714)
Kingston	265	SE Unit-8	LRTR	$6,203,453	$605,058	$0	$0	$0	$11,803	($55,714)
Kingston	265	SE Unit-9	LRTR	$6,203,453	$605,058	$0	$0	$0	$11,803	($55,714)
J. K. Spruce Power Plant	493	SE Unit-1	Membrane	$9,895,782	$517,572	$0	$0	$0	$0	($311,766)
J. K. Spruce Power Plant	493	SE Unit-2	Membrane	$5,135,786	$268,613	$0	$0	$0	$0	($161,803)
OVEC - Kyger Creek Station	771	SE Unit-1	LRTR	$2,449,618	$143,149	$0	$0	$0	$25,081	$0
OVEC - Kyger Creek Station	771	SE Unit-2	LRTR	$2,449,618	$143,149	$0	$0	$0	$25,081	$0
OVEC - Kyger Creek Station	771	SE Unit-3	LRTR	$1,633,079	$95,432	$0	$0	$0	$16,720	$0
OVEC - Kyger Creek Station	771	SE Unit-4	LRTR	$1,633,079	$95,432	$0	$0	$0	$16,720	$0
OVEC - Kyger Creek Station	771	SE Unit-5	LRTR	$1,633,079	$95,432	$0	$0	$0	$16,720	$0
Williams Station	864	SE Unit-1	LRTR	$4,696,336	$390,166	$0	$0	$0	$0	$0
Muscatine Power and Water Generating Station	904	SE Unit-4	Membrane	$9,100,654	$660,809	$0	$0	$0	$0	($473,569)
Plant E C Gaston	928	SE Unit-5	LRTR	$29,338,963	$1,013,234	$0	$0	$0	$100,323	($473,569)

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Table 4. Generating Unit-Level Costs for FGD Wastewater Treatment under Regulatory Option A

[In pre-tax 2018 dollars]

Plant Name	Plant ID	Unit ID	Treatment Technology	Capital Cost	Annual O&M Cost	One Time Cost	Recurring Costs			
							3-Year O&M Cost	5-Year O&M Cost	6-Year O&M Cost	10-Year O&M Cost
Mitchell Plant	1236	SE Unit-1	LRTR	$6,731,961	$332,947	$0	$0	$0	$50,161	$0
Mitchell Plant	1236	SE Unit-2	LRTR	$6,731,961	$332,947	$0	$0	$0	$50,161	$0
EME Homer City Generation L.P.	1381	SE Unit-3	LRTR	$6,153,225	$527,073	$0	$0	$0	$100,323	$0
Plant James H Miller Jr	1493	SE Unit-1	LRTR	$0	$18,998	$0	$0	$0	$0	$0
Plant James H Miller Jr	1493	SE Unit-2	LRTR	$0	$18,871	$0	$0	$0	$0	$0
Plant James H Miller Jr	1493	SE Unit-3	LRTR	$0	$18,871	$0	$0	$0	$0	$0
Plant James H Miller Jr	1493	SE Unit-4	LRTR	$0	$18,871	$0	$0	$0	$0	$0
Trimble County	1674	SE Unit-1	LRTR	$1,593,214	$191,370	$0	$0	$0	$0	$0
Trimble County	1674	SE Unit-A	LRTR	$11,192,178	$1,344,356	$0	$0	$0	$0	$0
Marion Generating Station	1957	SE Unit-2	Membrane	$12,295,379	$910,816	$0	$0	$0	$0	($473,569)
James E Rogers Energy Complex (f.k.a. Cliffside Steam Station)	2079	SE Unit-5	LRTR	$0	$75,613	$0	$0	$0	$0	$0
Georgia Power Company - Plant Bowen	2244	SE Unit-1	LRTR	$6,940,643	$320,154	$0	$0	$0	$24,270	$0
Georgia Power Company - Plant Bowen	2244	SE Unit-2	LRTR	$8,645,887	$398,813	$0	$0	$0	$30,233	$0
Georgia Power Company - Plant Bowen	2244	SE Unit-3	LRTR	$6,671,394	$307,734	$0	$0	$0	$23,328	$0
Georgia Power Company - Plant Bowen	2244	SE Unit-4	LRTR	$6,432,062	$296,694	$0	$0	$0	$22,492	$0
Conemaugh	2268	SE Unit-1	LRTR	$411,608	$37,806	$0	$0	$0	$0	$0
Conemaugh	2268	SE Unit-2	LRTR	$411,608	$37,806	$0	$0	$0	$0	$0

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Table 4. Generating Unit-Level Costs for FGD Wastewater Treatment under Regulatory Option A

[In pre-tax 2018 dollars]

Plant Name	Plant ID	Unit ID	Treatment Technology	Capital Cost	Annual O&M Cost	One Time Cost	Recurring Costs			
							3-Year O&M Cost	5-Year O&M Cost	6-Year O&M Cost	10-Year O&M Cost
Chalk Point Generating Station	2297	SE Unit-1	LRTR	$3,876,191	$203,965	$0	$0	$0	$50,161	($236,784)
Chalk Point Generating Station	2297	SE Unit-2	LRTR	$3,876,191	$203,965	$0	$0	$0	$50,161	($236,784)
Allen Steam Station	2550	SE Unit-1	BPT/Retire	$0	$0	$0	$0	$0	$0	$0
Allen Steam Station	2550	SE Unit-2	BPT/Retire	$0	$0	$0	$0	$0	$0	$0
Allen Steam Station	2550	SE Unit-3	BPT/Retire	$0	$0	$0	$0	$0	$0	$0
Allen Steam Station	2550	SE Unit-4	BPT/Retire	$0	$0	$0	$0	$0	$0	$0
Allen Steam Station	2550	SE Unit-5	BPT/Retire	$0	$0	$0	$0	$0	$0	$0
Ghent	2601	SE Unit-1	LRTR	$2,390,119	$195,553	$0	$0	$0	$0	$0
Ghent	2601	SE Unit-2	LRTR	$2,671,309	$218,559	$0	$0	$0	$0	$0
Ghent	2601	SE Unit-3	LRTR	$1,546,547	$126,534	$0	$0	$0	$0	$0
Ghent	2601	SE Unit-4	LRTR	$2,460,416	$201,305	$0	$0	$0	$0	$0
Wateree Station	3087	SE Unit-1	Membrane	$7,732,273	$749,077	$0	$0	$0	$0	($236,784)
Wateree Station	3087	SE Unit-2	Membrane	$7,732,273	$749,077	$0	$0	$0	$0	($236,784)
PSNH - Merrimack Station	3095	SE Unit-1	Existing Evap	$0	$0	$0	$0	$0	$0	$0
PSNH - Merrimack Station	3095	SE Unit-2	Existing Evap	$0	$0	$0	$0	$0	$0	$0
C D McIntosh Jr. Power Plant	3200	SE Unit-3	BPT/Retire	$0	$0	$0	$0	$0	$0	$0
Cross Generating Station	3235	SE Unit-1	LRTR	$550,221	$41,344	$0	$0	$0	$0	$0
Cross Generating Station	3235	SE Unit-2	LRTR	$550,221	$41,344	$0	$0	$0	$0	$0
Cross Generating Station	3235	SE Unit-3	LRTR	$2,200,885	$165,378	$0	$0	$0	$0	$0
Cross Generating Station	3235	SE Unit-4	LRTR	$2,670,191	$200,642	$0	$0	$0	$0	$0
Cardinal	3265	SE Unit-1	LRTR	$3,999,390	$238,685	$0	$0	$0	$18,107	$0

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Table 4. Generating Unit-Level Costs for FGD Wastewater Treatment under Regulatory Option A

[In pre-tax 2018 dollars]

Plant Name	Plant ID	Unit ID	Treatment Technology	Capital Cost	Annual O&M Cost	One Time Cost	Recurring Costs			
							3-Year O&M Cost	5-Year O&M Cost	6-Year O&M Cost	10-Year O&M Cost
Cardinal	3265	SE Unit-2	LRTR	$4,539,848	$270,940	$0	$0	$0	$20,554	$0
Cardinal	3265	SE Unit-3	LRTR	$13,619,543	$812,819	$0	$0	$0	$61,662	$0
Lawrence Energy Center	3309	SE Unit-2	Membrane	$2,944,860	$430,547	$0	$0	$0	$0	$0
Lawrence Energy Center	3309	SE Unit-3	Membrane	$515,351	$75,346	$0	$0	$0	$0	$0
W. A. Parish E.G.S.	3464	SE Unit-8	LRTR	$4,741,178	$370,321	$0	$0	$0	$0	$0
Marshall Steam Station	3597	SE Unit-1	LRTR	$0	$14,302	$0	$0	$0	$0	$0
Marshall Steam Station	3597	SE Unit-2	LRTR	$0	$14,302	$0	$0	$0	$0	$0
Marshall Steam Station	3597	SE Unit-3	LRTR	$0	$30,156	$0	$0	$0	$0	$0
Marshall Steam Station	3597	SE Unit-4	LRTR	$0	$16,852	$0	$0	$0	$0	$0
Mill Creek	3604	SE Unit-1	LRTR	$1,139,967	$90,788	$0	$0	$0	$0	$0
Mill Creek	3604	SE Unit-2	LRTR	$1,139,967	$90,788	$0	$0	$0	$0	$0
Mill Creek	3604	SE Unit-3	LRTR	$1,468,072	$116,919	$0	$0	$0	$0	$0
Mill Creek	3604	SE Unit-4	LRTR	$1,812,838	$144,376	$0	$0	$0	$0	$0
E.W. Brown	3672	SE Unit-3	Membrane	$2,658,085	$525,178	$0	$0	$0	$0	$0
RRI Energy Keystone Generating Station	3831	SE Unit-1	LRTR	$3,264,338	$271,723	$0	$0	$0	$0	$0
RRI Energy Keystone Generating Station	3831	SE Unit-2	LRTR	$3,264,338	$271,723	$0	$0	$0	$0	$0
Indianapolis Power & Light Company - Petersburg Generating Station	3997	SE Unit-3	Existing Evap	$0	$0	$0	$0	$0	$0	$0
Indianapolis Power & Light Company - Petersburg Generating Station	3997	SE Unit-4	Existing Evap	$0	$0	$0	$0	$0	$0	$0
PPL Brunner Island	4122	SE Unit-1	BPT/Retire	$0	$0	$0	$0	$0	$0	$0
PPL Brunner Island	4122	SE Unit-2	BPT/Retire	$0	$0	$0	$0	$0	$0	$0

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Table 4. Generating Unit-Level Costs for FGD Wastewater Treatment under Regulatory Option A

[In pre-tax 2018 dollars]

Plant Name	Plant ID	Unit ID	Treatment Technology	Capital Cost	Annual O&M Cost	One Time Cost	Recurring Costs			
							3-Year O&M Cost	5-Year O&M Cost	6-Year O&M Cost	10-Year O&M Cost
PPL Brunner Island	4122	SE Unit-3	BPT/Retire	$0	$0	$0	$0	$0	$0	$0
Brandon Shores	4237	SE Unit-1	LRTR	$6,831,347	$336,932	$0	$0	$0	$50,161	$0
Brandon Shores	4237	SE Unit-2	LRTR	$6,831,347	$336,932	$0	$0	$0	$50,161	$0
Monroe Power Plant	4533	SE Unit-1	LRTR	$3,413,408	$356,010	$0	$0	$0	$23,480	$0
Monroe Power Plant	4533	SE Unit-2	LRTR	$4,043,785	$421,757	$0	$0	$0	$27,816	$0
Monroe Power Plant	4533	SE Unit-3	LRTR	$3,563,705	$371,686	$0	$0	$0	$24,514	$0
Monroe Power Plant	4533	SE Unit-4	LRTR	$3,563,705	$371,686	$0	$0	$0	$24,514	$0
Mountaineer Plant	4543	SE Unit-1	LRTR	$0	$75,613	$0	$0	$0	$0	$0
TransAlta Centralia Generation, LLC	4547	SE Unit-2	BPT/Retire	$0	$0	$0	$0	$0	$0	$0
Dominion - Chesterfield Power Station	4679	SE Unit-3	LRTR	$2,216,680	$147,339	$0	$0	$0	$21,936	$0
Dominion - Chesterfield Power Station	4679	SE Unit-4	LRTR	$7,921,103	$526,503	$0	$0	$0	$78,387	$0
Dickerson Generating Station	5015	SE Unit-1	CP	$644,703	$8,607	$0	$0	$0	$33,441	$0
Dickerson Generating Station	5015	SE Unit-2	CP	$644,703	$8,607	$0	$0	$0	$33,441	$0
Dickerson Generating Station	5015	SE Unit-3	CP	$644,703	$8,607	$0	$0	$0	$33,441	$0
Georgia Power Company - Plant Wansley	5043	SE Unit-1	LRTR	$4,433,210	$246,445	$0	$0	$0	$0	$0
Georgia Power Company - Plant Wansley	5043	SE Unit-2	LRTR	$4,298,870	$238,977	$0	$0	$0	$0	$0
Clifty Creek Station	5318	SE Unit-1	LRTR	$1,992,295	$114,870	$0	$0	$0	$16,720	$0
Clifty Creek Station	5318	SE Unit-2	LRTR	$1,992,295	$114,870	$0	$0	$0	$16,720	$0
Clifty Creek Station	5318	SE Unit-3	LRTR	$1,992,295	$114,870	$0	$0	$0	$16,720	$0
Clifty Creek Station	5318	SE Unit-4	LRTR	$1,992,295	$114,870	$0	$0	$0	$16,720	$0

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Table 4. Generating Unit-Level Costs for FGD Wastewater Treatment under Regulatory Option A

[In pre-tax 2018 dollars]

Plant Name	Plant ID	Unit ID	Treatment Technology	Capital Cost	Annual O&M Cost	One Time Cost	Recurring Costs			
							3-Year O&M Cost	5-Year O&M Cost	6-Year O&M Cost	10-Year O&M Cost
Clifty Creek Station	5318	SE Unit-5	LRTR	$1,992,295	$114,870	$0	$0	$0	$16,720	$0
Clifty Creek Station	5318	SE Unit-6	LRTR	$1,992,295	$114,870	$0	$0	$0	$16,720	$0
Cumberland	6329	SE Unit-1	CP	$96,928,430	$8,672,561	$0	$0	$0	$100,323	($473,569)
Cumberland	6329	SE Unit-2	CP	$96,928,430	$8,672,561	$0	$0	$0	$100,323	($473,569)
Leland Olds Station	6334	SE Unit-1	Membrane	$9,885,390	$772,845	$0	$0	$0	$0	$0
Leland Olds Station	6334	SE Unit-2	Membrane	$12,549,971	$981,163	$0	$0	$0	$0	$0
Tampa Electric - Big Bend Station	6377	SE Unit-3	LRTR	$5,424,238	$603,106	$0	$0	$0	$33,441	($157,856)
Tampa Electric - Big Bend Station	6377	SE Unit-4	LRTR	$10,848,476	$1,206,213	$0	$0	$0	$66,882	($315,712)
Morgantown Generating Station (f.k.a. Mirant Mid-Atlantic, LLC)	6616	SE Unit-1	LRTR	$4,117,305	$205,284	$0	$0	$0	$50,161	($236,784)
Morgantown Generating Station (f.k.a. Mirant Mid-Atlantic, LLC)	6616	SE Unit-2	LRTR	$4,117,305	$205,284	$0	$0	$0	$50,161	($236,784)
Mayo Electric Generating Plant	6689	SE Unit-1	Existing Evap	$0	$0	$0	$0	$0	$0	$0
Winyah Generating Station	7411	SE Unit-1	BPT/Retire	$0	$0	$0	$0	$0	$0	$0
Winyah Generating Station	7411	SE Unit-2	BPT/Retire	$0	$0	$0	$0	$0	$0	$0
Plant Barry	7651	SE Unit-5	LRTR	$23,411,923	$537,508	$0	$0	$0	$100,323	($473,569)
EKPC Spurlock Station	7761	SE Unit-1	Existing Evap	$0	$0	$0	$0	$0	$0	$0
EKPC Spurlock Station	7761	SE Unit-2	Existing Evap	$0	$0	$0	$0	$0	$0	$0

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Table 4. Generating Unit-Level Costs for FGD Wastewater Treatment under Regulatory Option A

[In pre-tax 2018 dollars]

Plant Name	Plant ID	Unit ID	Treatment Technology	Capital Cost	Annual O&M Cost	One Time Cost	Recurring Costs			
							3-Year O&M Cost	5-Year O&M Cost	6-Year O&M Cost	10-Year O&M Cost
Seminole Generating Station	7785	SE Unit-1	LRTR	$10,646,963	$548,778	$0	$0	$0	$100,323	($473,569)
Plant Scherer	8179	SE Unit-1	Membrane	$3,487,280	$508,482	$0	$0	$0	$0	$0
Plant Scherer	8179	SE Unit-2	Membrane	$3,487,280	$508,482	$0	$0	$0	$0	$0
Plant Scherer	8179	SE Unit-3	Membrane	$3,487,280	$508,482	$0	$0	$0	$0	$0
Plant Scherer	8179	SE Unit-4	Membrane	$3,487,280	$508,482	$0	$0	$0	$0	$0
Miami Fort Station	8308	SE Unit-2	LRTR	$2,892,535	$244,035	$0	$0	$0	$0	$0
Miami Fort Station	8308	SE Unit-3	LRTR	$3,273,524	$276,178	$0	$0	$0	$0	$0
Jeffrey Energy Center	8353	SE Unit-1	LRTR	$4,528,857	$225,912	$0	$0	$0	$33,441	$0
Jeffrey Energy Center	8353	SE Unit-2	LRTR	$4,528,857	$225,912	$0	$0	$0	$33,441	$0
Jeffrey Energy Center	8353	SE Unit-3	LRTR	$4,528,857	$225,912	$0	$0	$0	$33,441	$0
Belews Creek Steam Station	8661	SE Unit-1	LRTR	$0	$35,286	$0	$0	$0	$0	$0
Belews Creek Steam Station	8661	SE Unit-2	LRTR	$0	$40,327	$0	$0	$0	$0	$0
AmerenUE Sioux Power Plant	8902	SE Unit-1	LRTR	$44,589,546	$3,096,818	$0	$0	$0	$50,161	$0
AmerenUE Sioux Power Plant	8902	SE Unit-2	LRTR	$44,589,546	$3,096,818	$0	$0	$0	$50,161	$0
F.B. Culley Generating Station	8965	SE Unit-3	LRTR	$5,065,976	$341,143	$0	$0	$0	$0	$0
John E. Amos Plant	9161	SE Unit-1	LRTR	$21,304,868	$1,067,676	$0	$0	$0	$64,408	$0
John E. Amos Plant	9161	SE Unit-2	LRTR	$6,911,689	$346,374	$0	$0	$0	$20,895	$0
John E. Amos Plant	9161	SE Unit-3	LRTR	$4,968,349	$248,985	$0	$0	$0	$15,020	$0
Fort Martin Power Station	9225	SE Unit-1	LRTR	$5,437,139	$285,143	$0	$0	$0	$49,598	($234,124)
Fort Martin Power Station	9225	SE Unit-2	LRTR	$5,560,710	$291,623	$0	$0	$0	$50,725	($239,445)
Roxboro Steam Plant	9391	SE Unit-1	LRTR	$0	$19,491	$0	$0	$0	$0	$0
Roxboro Steam Plant	9391	SE Unit-2	LRTR	$0	$19,560	$0	$0	$0	$0	$0

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Table 4. Generating Unit-Level Costs for FGD Wastewater Treatment under Regulatory Option A

[In pre-tax 2018 dollars]

Plant Name	Plant ID	Unit ID	Treatment Technology	Capital Cost	Annual O&M Cost	One Time Cost	Recurring Costs			
							3-Year O&M Cost	5-Year O&M Cost	6-Year O&M Cost	10-Year O&M Cost
Roxboro Steam Plant	9391	SE Unit-3	LRTR	$0	$18,454	$0	$0	$0	$0	$0
Roxboro Steam Plant	9391	SE Unit-4	LRTR	$0	$18,108	$0	$0	$0	$0	$0
W H Zimmer Station	9475	SE Unit-1	LRTR	$5,189,386	$452,866	$0	$0	$0	$0	$0
PPL Montour	9805	SE Unit-1	LRTR	$3,663,749	$262,104	$0	$0	$0	$50,161	$0
PPL Montour	9805	SE Unit-2	LRTR	$3,663,749	$262,104	$0	$0	$0	$50,161	$0
Cheswick Power Station	9948	SE Unit-1	LRTR	$7,055,365	$460,729	$0	$0	$0	$100,323	$0
Dallman	9971	SE Unit-1	LRTR	$3,671,359	$244,512	$0	$0	$0	$37,715	$0
Dallman	9971	SE Unit-2	LRTR	$2,569,952	$171,158	$0	$0	$0	$26,401	$0
Dallman	9971	SE Unit-3	LRTR	$1,835,680	$122,256	$0	$0	$0	$18,858	$0
Dallman	9971	SE Unit-4	LRTR	$1,688,825	$112,475	$0	$0	$0	$17,349	$0
Elm Road Generating Station	56068	SE Unit-A	LRTR	$2,902,460	$273,581	$0	$0	$0	$0	$0
Elm Road Generating Station	56068	SE Unit-B	LRTR	$2,902,460	$273,581	$0	$0	$0	$0	$0

EXHIBIT 5

APPALACHIAN POWER COMPANY
WHEELING POWER COMPANY
DIRECT TESTIMONY
OF
BRIAN D. SHERRICK

COMPANY EXHIBIT BDS-D

DIRECT TESTIMONY OF
BRIAN D. SHERRICK
ON BEHALF OF APPALACHIAN POWER COMPANY AND
WHEELING POWER COMPANY
BEFORE THE PUBLIC SERVICE COMMISSION
OF WEST VIRGINIA IN CASE NO. 20-_____

Q. PLEASE STATE YOUR NAME, BUSINESS ADDRESS, AND POSITION.

A. My name is Brian D. Sherrick. My business address is 1 Riverside Plaza, Columbus, Ohio 43215. I am employed by American Electric Power Service Corporation ("AEPSC") as the Managing Director of Projects for the American Electric Power Company, Inc. ("AEP") Generation Projects Controls and Construction organization. AEPSC is a wholly-owned subsidiary of AEP, the parent of Appalachian Power Company ("APCo") and Wheeling Power Company ("WPCo").

Q. PLEASE SUMMARIZE YOUR EDUCATIONAL BACKGROUND AND BUSINESS EXPERIENCE.

A. I received a Bachelor of Science Degree in Civil Engineering from the United States Military Academy in 1997 and a Master's of Civil Engineering Degree from University of Missouri Rolla in 2002. I hold a Project Management Professional certification from the Project Management Institute. My professional experiences includes over 7 years as an Engineer in the U.S. Army and over 16 years working for AEP on new build and retrofit projects for coal, natural gas, solar, and wind power plants and their associated environmental controls. I have held various positions of increasing responsibility including Project Manager, Project Controls Manager, Startup and Commissioning Manager, Project Director, Director of Construction, and in 2020, I assumed my current position of Managing Director of Projects.

Q. FOR WHOM ARE YOU TESTIFYING IN THIS PROCEEDING?

A. I am testifying on behalf of both APCo and WPCo (together, "the Companies").

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my direct testimony is to describe the potential Coal Combustion Residual ("CCR") and Steam Electric Effluent Limitations Guidelines ("ELG") compliance strategies regarding the Amos Plant, the Mountaineer Plant, and the Mitchell Plant "(the Plants"). Specifically, I will describe the current state of the Plants as well as the scope, cost, schedule, and project management methodology that AEPSC, on behalf of APCo and WPCo, would use for the projects.

Q. ARE YOU SPONSORING ANY SCHEDULES IN THIS PROCEEDING?

A. I am sponsoring the following Exhibits:

- Company Exhibit BDS-D1 – Amos Project Cost Estimate
- Company Exhibit BDS-D2 – Mountaineer Project Cost Estimate
- Company Exhibit BDS-D3 – Mitchell Project Cost Estimate
- Company Exhibit BDS-D4 – Amos Project Schedule
- Company Exhibit BDS-D5 – Mountaineer Project Schedule
- Company Exhibit BDS-D6 – Mitchell Project Schedule
- Company Exhibit BDS-D7 – Other Cost Estimates

I. PROJECT OVERVIEW

Q. PLEASE DESCRIBE THE PLANTS.

A. The Amos Plant is located approximately 15 miles northwest of Charleston, West Virginia on the Kanawha River. APCo owns 100% interest in the Amos Plant, which is comprised of three super-critical pulverized coal-fired base-load generating units. The nameplate Amos Unit capacities are 800MW each for Amos Units 1 & 2 and 1,330 MW for Amos Unit 3 for a total nameplate capacity of 2,930 MW. The units were placed in service in 1971, 1972, and

1973 respectively. Each unit is equipped with an electrostatic precipitator for control of particulate matter, a flue gas desulfurization ("FGD") system for sulfur dioxide control, both selective catalytic reduction technology and low-NO_x burners for control of NO_x emissions, and utilize a dry fly ash handling system. All three units currently transport bottom ash and miscellaneous wastewater streams to a shared pond system where the bottom ash is later dredged and trucked to a permitted landfill. The bottom ash transport water ("BATW") and miscellaneous wastewater streams are then discharged to the Kanawha River through a National Pollution Discharge Elimination System ("NPDES") permitted outfall.

The Mountaineer Plant is located approximately 12 miles northeast of Point Pleasant, West Virginia on the Ohio River. APCo owns 100% interest in the Mountaineer Plant, which has one super-critical pulverized coal-fired base-load generating unit with a 1,320 MW nameplate capacity placed in service in 1980. The plant is equipped with an electrostatic precipitator for control of particulate matter, a FGD system for sulfur dioxide control, both selective catalytic reduction technology and low-NO_x burners for control of NO_x emissions, a dry fly ash handling system, and a Biological Treatment System for FGD wastewaters. The plant currently transports bottom ash and miscellaneous wastewater streams to a pond system where the bottom ash is later dredged and trucked to a permitted landfill. The BATW and miscellaneous wastewater streams are then discharged to the Ohio River through a NPDES permitted outfall.

The Mitchell Plant is located approximately 12 miles south of Moundsville, West Virginia on the Ohio River. Kentucky Power Company and WPCo each own an undivided 50% interest in the Mitchell Plant. The plant comprises two super-critical pulverized coal-fired base-load generating units. Mitchell Unit 1 has a capacity of 770 MW and Mitchell

Unit 2 has a capacity of 790 MW for a total capacity of 1,560 MW. Both units were placed in service in 1971. Each unit is equipped with an electrostatic precipitator for control of particulate matter, FGD system for sulfur dioxide control, and both selective catalytic reduction technology and low-NOx burners for control of NOx emissions. Both units also utilize a dry fly ash handling system. Both units currently transport bottom ash and miscellaneous wastewater streams to a shared pond system where the bottom ash is later dredged and trucked to a permitted landfill. The BATW and miscellaneous wastewater streams are then discharged to the Ohio River through a NPDES permitted outfall.

Q. HOW WERE THE SCOPES OF THE CCR AND ELG PROJECTS AT THE PLANTS DETERMINED?

A. The scopes of the CCR and ELG compliance projects were determined through collaboration among AEPSC's Environmental Services, Engineering Services, Fossil & Hydro Generation, and Projects departments. As described in the testimony of Company witness Spitznogle, the Environmental Services department analyzed the rules, then the project teams determined the operational changes at the plants that would be required to comply with the CCR and ELG rules under the various compliance scenarios laid out under the rules. Considering the timing requirements of various compliance scenarios established under the regulations, the Projects department then worked with a third party vendor to develop schedules and cost estimates for the various compliance strategies at the Plants. Estimates for multiple strategies were provided to Company witness Martin, who performed an economic analysis of them.

Q. PLEASE BRIEFLY DESCRIBE THE SCOPE OF CCR AND ELG PROJECTS AT THE AMOS, MOUNTAINEER, AND MITCHELL PLANTS.

A. A project that would allow the Amos Plant to continue to operate under the CCR requirements would require (i) removing ash from the Bottom Ash 1A and 1B, Reclaim, and Clear Water ponds; (ii) closing pond 1A and grading and seeding to establish natural drainage; (iii) lining the existing Reclaim and Clearwater ponds; (iv) constructing a new Lined Wastewater pond in place of Bottom Ash Pond 1B; (v) and installing a chemical treatment system for non-CCR wastewater streams. A project that would allow the Mountaineer Plant to continue to operate under the CCR requirements would require (i) removing ash from the east and west Bottom Ash ponds; (ii) lining the cleaned east and west ponds to create east and west Wastewater Settling ponds; (iii) installing a chemical treatment system for non-CCR wastewater streams; and (iv) potentially installing ground water remediation equipment. A project that would allow the Mitchell Plant to continue to operate under the CCR requirements would require (i) removing ash from the existing ponds; (ii) over excavating the ponds to ensure closure by removal; (iii) installing a new liner system in the footprint of the existing bottom ash pond to accept current CCR and non-CCR wastewater streams; and (iv) installing a chemical treatment system for non-CCR wastewater streams.

A project that would allow the Amos Plant to continue to operate under the ELG requirements would require (i) modifications to the bottom ash handling systems to no longer allow the discharge of BATW, including the installation of submerged grind conveyor systems; (ii) installation of two new ash bunkers; (iii) retrofitting economizer ash handling systems on Units 1 & 2; and (iv) installation of a new FGD Biological Treatment System with Ultrafiltration. A project that would allow the Mountaineer Plant to continue to operate under the ELG requirements would require (i) modifications to the bottom ash handling

system to no longer allow discharge of BATW including installation of a submerged grind conveyor system; (ii) installation of a new ash bunker; (iii) and retrofit of a new Ultrafiltration system onto the existing FGD Biological Treatment System. A project that would allow the Mitchell plant to operate under the ELG requirements would require (i) modifications to the bottom ash handling systems to no longer allow the discharge of BATW, including the installation of submerged grind conveyor systems; (ii) installation of a new ash bunker; and (iii) installation of a new FGD Biological Treatment System with Ultrafiltration.

Q. DID AEPSC EVALUATE ALTERNATE OPTIONS OR TECHNOLOGIES TO COMPLY WITH THE CCR AND ELG RULES?

A. Yes. AEPSC on behalf of the Companies evaluated options including installing large concrete troughs and remote dewatering conveyors. The ELG compliance options involved evaluating different vendor options to convert the wet bottom ash handling systems to dry systems. AEPSC also evaluated closed loop recycle systems for the Amos and Mitchell plants. Given the rule and operations requirements for all the plants, the project teams selected the technically feasible, least life cycle technology cost options for different compliance scenarios.

II. PROJECT SCHEDULE AND PLANNING

Q. DOES AEP GENERATION HAVE A STANDARD PROCESS THAT IT FOLLOWS TO PLAN AND CONSTRUCT ENVIRONMENTAL PROJECTS FOR ALL OF THE PROJECTS YOU DISCUSS IN YOUR TESTIMONY?

A. Yes. All project execution is governed by AEP's commitment to safety and utilizes a phased planning and construction process. The process includes management of procurement, cost,

schedule, quality, and risk in accordance with quality assurance documents that follow industry standard project management practices.

Q. PLEASE DESCRIBE THE PHASED APPROACH TO PROJECT PLANNING AND EXECUTION.

A. The projects are executed from planning through completion using the same phased (stage) approach that has been successfully employed by AEP on many past projects:

- Stages 0 (Initiation) and 1 (Business Planning & Screening) are conducted during long range planning activities and typically before the first Capital Improvement Requisition (CI) funding gate. Stage 1 may include feasibility studies as required to meet project schedules.
- Stage 2 (Scope Selection) includes conducting and/or closing out feasibility studies and evaluation of risk balanced technical options.
- Stages 3 (Preliminary Engineering) and 4 (Detailed Engineering) consists of completing conceptual engineering, detailed engineering and design, permitting, and procurement of long lead-time equipment and supplies. It may include initial site construction activities.
- Stages 5 (Construction), 6 (Commissioning and Startup), and 7 (Close Out) consists of full-scale construction, startup, commissioning, and close out activities.

A detailed evaluation and review of the scope, schedule, and estimate are conducted between each funding request (Capital Improvement Requisition) to confirm the project is meeting project objectives. It also allows the project team to report progress to the Companies management with respect to project success criteria, and any critical risks or

opportunities that may have been identified, before obtaining financial authorization to proceed.

Q. PLEASE DESCRIBE THE ACTIVITIES THAT OCCUR DURING STAGE 2.

A. Stage 2 begins with the preparation and approval of a Capital Improvement Requisition (funding request) approving funding for Stage 2 activities. An architect/engineer is then contracted to perform the engineering, design, and feasibility studies for Stage 2 and the ensuing stages of the project. The intent of the Stage 2 feasibility studies is to investigate the technical options and factors driving the project cost and schedule. During Stage 2, the architect/engineer, with input from a team of AEPSC engineers and managers, defines the scope of the project, prepares work plans, and develops a budgetary cost estimate and schedule for implementation. In addition, preliminary environmental permitting activities begin, any necessary regulatory approvals are identified, and AEPSC begins conceptual engineering.

The results of the Stage 2 conceptual engineering and feasibility studies are then presented to senior management, and authorization is sought to proceed to Stages 3 and 4. Approval to proceed is accomplished by an Improvement Requisition revision request which typically includes a formal management meeting.

Q. WHAT ARE THE ACTIVITIES THAT TAKE PLACE IN STAGES 3 AND 4?

A. Stages 3 and 4 consist of preliminary engineering, detailed engineering and design, regulatory approval and permitting, and procurement work. During these stages, we refine the cost estimate and schedule, award the Original Equipment Manufacturer contract, procure long lead-time equipment, and develop engineering drawings to the point that detailed design work can begin.

Applicable modifications to existing air, water, and waste environmental permits are submitted to the state regulatory body to begin the evaluation and approval process. In addition, construction and site management teams begin design evaluations to ensure that the proposed scope of work is optimized for constructability. The Companies also define site preparation plans, determine which, if any, facilities will need to be relocated, select site preparation contractor(s), and complete studies to support the various permitting activities that will be required.

The project team then proceeds to detailed engineering, design, contracting, and initial site construction work that can be performed prior to the final approval of applicable permits. During this stage, as detailed design progresses, construction bid packages are prepared and major equipment is specified, bid, and purchased. The construction and site management teams are mobilized and begin site construction work, and the team proceeds through the process of selecting and awarding the major construction contracts. Upon completion of Stages 3 and 4, the project is evaluated once again, and an Improvement Requisition revision is prepared for management approval to proceed with Stages 5 through 7.

Q. IN WHAT STAGE ARE THE CCR AND ELG PROJECTS CURRENTLY?

A. The Project Teams are currently performing Stage 3 and 4 activities as the Companies await receipt of permits, along with any necessary regulatory approvals to start Stage 5 activities.

Q. PLEASE DESCRIBE AEPSC'S PROJECT SCHEDULE MANAGEMENT PROCESS.

A. Schedule management ensures that the overall project is executed in support of the initial operation date. This is accomplished using scheduling tools, the monitoring of critical

milestones, and through the establishment and monitoring of specific performance and production metrics.

An integrated project schedule is developed using activities and criteria for planning, execution, monitoring, and control. The project schedule development involves activity sequencing and activity duration estimating to develop detailed project schedules so that monitoring and controls are in place to complete the project on or ahead of schedule. The scope of work for the project is subdivided into manageable work packages using a project Work Breakdown Structure, which facilitates project cost estimating, scheduling, and controlling activities.

AEPSC, acting on behalf of the Companies, assumes the primary responsibility for schedule management as the Schedule Integrator for the project. In that role, AEPSC accounts for the activities of ourselves, the architect/engineering contractor, equipment suppliers, and the construction contractors for the development of a fully integrated schedule. The contractors and vendors provide us with weekly comprehensive schedule activity updates along with monthly reports on project progress, a 30-day look ahead schedule, status of major activities, cost status updates, and other pertinent data. Schedules for the Amos, Mountaineer, and Mitchell compliance plans are shown in Company Exhibit BDS-D4 –Amos Project Schedule, Company Exhibit BDS-D5 –Mountaineer Project Schedule, and Company Exhibit BDS-D6 –Mitchell Project Schedule.

Q. PLEASE DESCRIBE AEP'S PROJECT SAFETY MANAGEMENT.

A. All projects are conducted with AEP's 'Zero Harm' safety culture. Zero Harm distills safety into a simple idea – "No one gets hurt and everyone goes home in the same or better condition than they came to work." On a project, it means every employee, contractor and

visitor, regardless of work location, is held accountable for the safety of themselves and each other. With this practice, a project can avoid unsafe activities and conditions that lead to accidents.

III. PROJECT COSTS

Q. PLEASE BRIEFLY DESCRIBE THE COSTS OF THE CCR AND ELG PROJECTS.

A. The total estimated cost of compliance that would allow the Amos Plant to continue to operate under the CCR and ELG requirements is $177.1 million, including $169.9 million in capital, $2.7 million in other charges, and $4.5 million in Asset Retirement Obligation (ARO) costs. A detailed breakdown of the Amos projects can be found in Company Exhibit BDS-D1 – Amos Project Cost Estimate.

The total estimated cost of compliance that would allow the Mountaineer Plant to continue to operate under the CCR and ELG requirements is $72.9 million, including $70.1 million in capital, $2.4 million in other charges, and $433,000 in ARO costs. A detailed breakdown of the Mountaineer projects can be found in Company Exhibit BDS-D2 – Mountaineer Project Cost Estimate.

The total estimated cost of compliance that would allow the Mitchell Plant to continue to operate under the CCR and ELG requirements is $133.5 million, including $131.5 million in capital, $1.8 million in other charges, and $166,000 in Asset Retirement Obligation (ARO) costs. A detailed breakdown of the Project can be found in Company Exhibit BDS-D3 – Mitchell Cost Estimates.

The cost estimates were developed by an independent engineering firm with inputs and oversight from AEPSC. AEPSC reviewed the independent consultant's estimate for completeness and included AEPSC's costs and contingency to arrive at the total project cost

estimate. The cost estimates, including projects not selected, are included Company Exhibit BDS-D7 – Other Cost Estimates. AEPSC has successfully used this cost estimation procedure for other construction projects throughout the AEP system.

I provided these cost estimates to Company witness Martin for the purposes of the economic analysis he supports in his testimony in this proceeding.

IV. OTHER EVALUATED PROJECTS

Q. WERE ANY COST ESTIMATES DEVELOPED FOR OTHER COMPLIANCE OPTIONS CONSIDERED AT THE PLANTS FOR CCR AND ELG?

A. Yes, multiple compliance options were considered for the Amos, Mountaineer, and Mitchell Plants based on input from the Companies and AEPSC.

Aside from the previously described options to achieve compliance with all requirements of the CCR and ELG rules at the Amos, Mountaineer, and Mitchell Plants, cost estimates were also developed for the following scenarios:

- Perform "CCR Only" compliance projects at the Amos, Mountaineer, and Mitchell Plants, and retire the plants in 2028 under the ELG retirement option.
- Perform the full CCR and ELG compliance projects at the Mountaineer and two Amos units, but retire one of the 800 MW units at the Amos Plant under the ELG retirement option.

These cost estimates were provided to Company witnesses Martin and Beam.

Q. PLEASE DETAIL THE CCR PROJECTS THAT RESULT IN THE CESSATION OF OPERATIONS AT AMOS, MOUNTAINEER, AND MITCHELL BY DECEMBER 31, 2028.

A. The "CCR Only" option would involve removing ash from the existing ponds, over excavating the ponds to ensure closure by removal, and installing new chemical treatment equipment and lined pond systems to accept BATW and other current wastewater streams with new ARO costs. After cessation of operation in December 2028, APCo and WPCo would have up to 5 years to close, by removal, the new pond systems with the newly established ARO costs. Under this option, the total estimated cost of the "CCR Only" Amos Projects is $72.7 million, including $52.1 million in capital, $3.7 million in other charges, and $16.9 million in ARO costs. For Mountaineer, the total estimated costs of the "CCR Only" Mountaineer Project is $52.1 million, including $19.3 million in capital, $3.4 million in other charges, and $29.5 million in ARO costs. For Mitchell, the total estimated costs of the "CCR Only" Mitchell Project is $35.1 million, including $25.2 million in capital, $2.4 million in other charges, and $7.5 million in ARO costs. A detailed breakdown of these projects can be found in Company Exhibit BDS-D7 – Other Cost Estimates.

Q. PLEASE DETAIL THE PROJECT THAT RESULTS IN RETIRING ONE OF THE TWO 800 MW AMOS UNITS AND MOVING FORWARD WITH THE CCR AND ELG PROJECTS FOR ALL OTHER UNITS.

A. From a CCR perspective, the Amos plant was configured so that all three units share the pond system, which is a more efficient approach than individual ponds for each unit (lower capital, operations, and maintenance costs). If APCo only retrofitted the pond system for two units, it would still have to perform roughly the same amount of work to create smaller ponds while installing the same systems and configurations.

From an ELG perspective, this option would entail installing dry bottom ash handling equipment on only one of the 800 MW units in addition to the 1330 MW Unit 3. The

Company would still be required to install an ash bunker for the remaining 800 MW unit, an economizer ash handling system for the remaining 800 MW unit, and FGD wastewater treatment equipment for the remaining two units. Under this option, the ash bunker and FGD wastewater treatment equipment could be marginally smaller than they would be if sized for compliance for all three units, which would result in a small cost savings relative to the cost of compliance projects for all three units. The reduction in costs for not installing ELG compliance technology on one of the 800 MW units would be approximately $37.0 million out of the $177.1 million as set forth above. The relative small savings would result in 800 MW less generation capacity.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

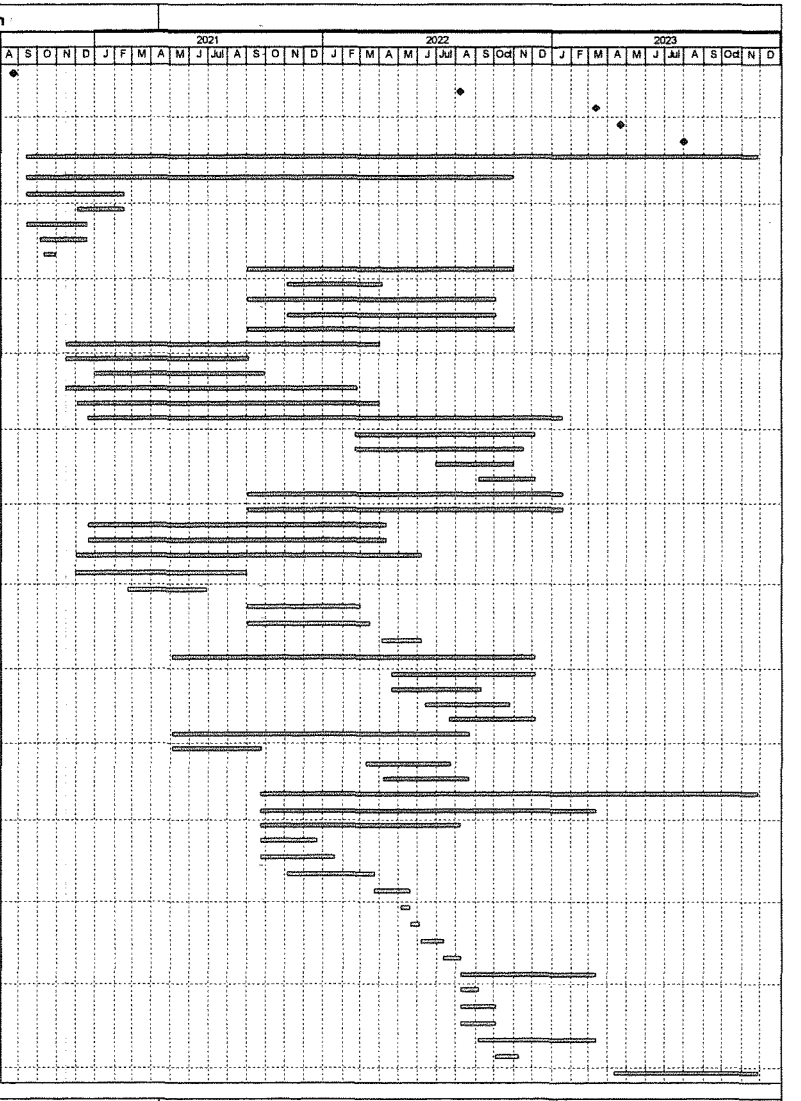
Mitchell CCR and ELG Project Cost Estimate

Unit & Scope	Pre-2020	2020	2021	2022	2023	2024	Total
ML1-2 Dry Ash Handling Capital	$ 341	$ 2,980	$ 4,870	$ 12,075	$ 36,351	$ -	$ 56,616
ML0 FGD WWT Capital	$ -	$ 413	$ 7,092	$ 15,877	$ 24,448	$ 982	$ 48,811
ML0 Pond Repurpose Capital	$ -	$ 343	$ 4,838	$ 8,930	$ 11,980	$ -	$ 26,091
ML0 Pond Repurpose Other	$ -	$ -	$ 182	$ 941	$ 711	$ -	$ 1,834
ML0 Pond Repurpose ARO	$ -	$ -	$ 17	$ 85	$ 64	$ -	$ 166
Total (Direct+Allocations)	**$ 341**	**$ 3,736**	**$ 16,999**	**$ 37,907**	**$ 73,554**	**$ 982**	**$ 133,519**

Company Exhibit BDS-D3
Page 1 of 1

Mitchell - CCR/ELG EPA Updated Timelines... | **AEP CCR-ELG MLP USEPA Public Version**

Activity ID	Activity Name	Duration (Months)	Start	Finish
T-00-M-020-SR-G-RPS-A80	AEP Release Engineer and OEM to Complete Detailed Design for CCR Compliance	0.0		24-Aug-20 A
T-PR-M-020-SR-G-RPS-A60	3rd Party QAQC Certification of CCR Materials Removed for West Ash Pond Closure by Removal	0.0		08-Aug-22
T-PR-M-600-SR-G-RPS-A20	Initial Operation of Repurposed West Wastewater Pond / All non-CCR Streams Routed through Lined Wastewater Pond	0.0		13-Mar-23
T-PR-M-020-SR-G-RPS-A40	Cease sluicing CCR from Unit 1 & 2 (CCR Compliance)	0.0		21-Apr-23
T-PR-M-020-SR-G-RPS-A80	3rd Party QAQC Certification of CCR Materials Removed for EastAsh Pond Closure by Removal	0.0		31-Jul-23
Mitchell Plant		33.4	Sep-20 A	Nov-23
Engineering & Design		22.2	Sep-20 A	Oct-22
Common		4.5	Sep-20 A	Feb-21
Civil / Site Infrastructure		2.1	Dec-20	Feb-21
Byproduct Handling		2.6	Sep-20 A	Dec-20
Mechanical BOP Systems		2.2	Oct-20 A	Dec-20
Electrical BOP Systems		0.6	Oct-20 A	Oct-20 A
BA Conversion		12.2	Sep-21	Oct-22
Civil / Site Infrastructure		4.3	Nov-21	Apr-22
Byproduct Handling		11.4	Sep-21	Oct-22
Mechanical BOP Systems		9.5	Nov-21	Oct-22
Electrical BOP Systems		12.2	Sep-21	Oct-22
Pond Repurpose		14.4	Nov-20	Mar-22
Civil / Site Infrastructure		8.4	Nov-20	Sep-21
Byproduct Handling		7.7	Jan-21	Sep-21
Mechanical BOP Systems		13.3	Nov-20	Feb-22
Electrical BOP Systems		13.8	Dec-20	Mar-22
Procurement		21.7	Dec-20	Jan-23
Common		8.2	Feb-22	Dec-22
Byproduct Handling		7.7	Feb-22	Nov-22
Mechanical BOP Systems		3.6	Jun-22	Oct-22
Electrical BOP Systems		2.6	Sep-22	Dec-22
BA Conversion		14.4	Sep-21	Jan-23
OEM Ash Handling Equipment Engineering / Design / Fabrication / Delivery		14.4	Sep-21	Jan-23
Pond Repurpose		13.6	Dec-20	Apr-22
Mechanical BOP Systems		13.6	Dec-20	Apr-22
Permitting		15.8	Dec-20	Jun-22
T-BA-E-100-E0-Z-000-A05	Prepare / Submit CPCN Application & Obtain Regulatory Approval from Public Service Commission	7.8	Dec-20	Aug-21
T-00-L-915-SP-MP-PMT-A60	Dam/Dike Modifications (Mitchell)	3.6	Feb-21	Jun-21
T-00-L-915-SP-MP-PMT-A90	Air Permit (Mitchell)	5.2	Sep-21	Mar-22
T-00-L-915-SP-MP-PMT-A70	NPDES (Mitchell)	5.6	Sep-21	Mar-22
T-00-L-915-SP-MP-PMT-A40	SWPPP (Mitchell)	1.8	Apr-22	Jun-22
Labor Contracts		16.6	May-21	Dec-22
Bottom Ash Conversion Labor Contracts		8.6	Apr-22	Dec-22
Civil		4.1	Apr-22	Sep-22
Mechanical / Structural		3.9	Jun-22	Oct-22
Electrical / I&C		3.9	Jul-22	Dec-22
Pond Repurpose & Closure Labor Contracts		13.6	May-21	Aug-22
Civil		4.1	May-21	Sep-21
Mechanical / Structural		3.9	Mar-22	Jul-22
Electrical / I&C		3.9	Apr-22	Aug-22
Construction		22.7	Sep-21	Nov-23
West Wastewater Pond Closure & Repurpose		15.3	Sep-21	Mar-23
West Bottom Ash Pond Closure		9.1	Sep-21	Aug-22
T-PC-C-100-C-CON-S1-20	Install sheet piling to establish isolation of West Bottom Ash Pond	2.6	Sep-21	Dec-21
T-PC-C-100-C-CON-S1-10	Install piping to divert pond inflows to East Bottom Ash Pond	3.4	Sep-21	Jan-22
T-PC-C-100-C-CON-S1-70	Remove CCR from East Bottom Ash Pond (For capacity and create settling basins)	4.0	Nov-21	Mar-22
T-PC-C-100-C-CON-S1-80	Install temporary Chemical Treatment System for East Bottom Ash Pond	1.6	Mar-22	May-22
T-PC-C-100-C-CON-S1-90	Prepare Sand Filters / Pumps for Operation in East Bottom Ash Pond	0.4	May-22	May-22
T-PC-C-100-C-CON-S1-30	Dewater West Bottom Ash Pond	0.4	May-22	Jun-22
T-PC-C-100-C-CON-S1-40	CCR & PVC Liner Material Removal from West Bottom Ash Pond	1.0	Jun-22	Jul-22
T-PC-C-100-C-CON-S1-50	QA/QC of CCR Removal	0.8	Jul-22	Aug-22
West Wastewater Pond Repurpose		6.2	Aug-22	Mar-23
T-PR-C-100-C-CON-S1-10	Subgrade prep for pond enhancement equipment area (Includes Area Fill)	0.8	Aug-22	Sep-22
T-PR-C-100-C-CON-S1-20	Subgrade prep for liner	1.6	Aug-22	Oct-22
T-PR-C-100-C-CON-S1-80	Compact Fill to Construct NS Dike of the Pond	1.6	Aug-22	Oct-22
T-PR-C-100-C-CON-S1-120	Tank Based Chemical Treatment System Installation	5.4	Sep-22	Mar-23
T-PR-C-100-C-CON-S1-50	Liner Installation (Double Liner)	1.1	Oct-22	Nov-22
East Bottom Ash Pond Closure & Repurpose		6.6	Apr-23	Nov-23

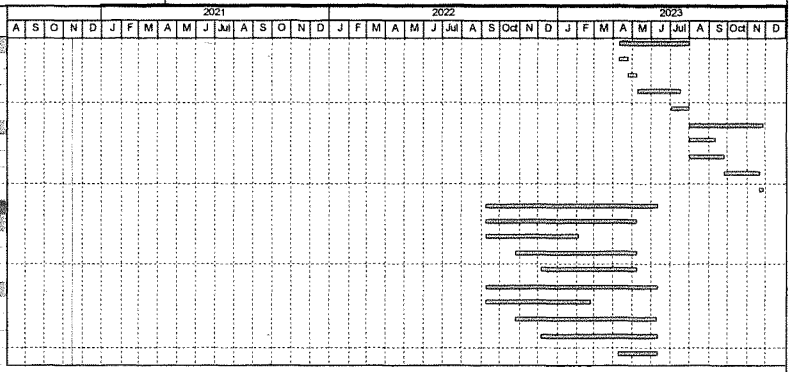


Current Bar Labels Summary
Milestone

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Mitchell - CCR/ELG EPA Updated Timelines... | **AEP CCR-ELG MLP USEPA Public Version**

Activity ID	Activity Name	Duration (Months)	Start	Finish
East Bottom Ash Pond Closure		3.2	Apr-23	Jul-23
T-PC-C-100-C-CON-S2-10	Dewater East Bottom Ash Pond	0.4	Apr-23	Apr-23
T-PC-C-100-C-CON-S2-15	Remove Sheet Piling	0.4	Apr-23	May-23
T-PC-C-100-C-CON-S2-25	CCR & PVC Liner Material Removal	2.0	May-23	Jul-23
T-PC-C-100-C-CON-S2-30	QA/QC of CCR Removal	0.8	Jul-23	Jul-23
East Wastewater Pond Repurpose		3.4	Aug-23	Nov-23
T-PR-C-100-C-CON-S2-15	Compact Fill to Construct Waste Decant Area	1.2	Aug-23	Sep-23
T-PR-C-100-C-CON-S2-10	Subgrade prep for liner	1.6	Aug-23	Sep-23
T-PR-C-100-C-CON-S2-20	Liner and protective cover installation (Double liner, Revetment)	1.6	Sep-23	Nov-23
T-PR-C-100-C-CON-S2-25	QA/QC Consultant Prepare East Wastewater Pond Certification for Operation	0.2	Nov-23	Nov-23
Bottom Ash Conversion Construction		7.8	Sep-22	Jun-23
Construction Unit 2		6.9	Sep-22	May-23
T-BA-C-492-C-CON-72	Civil (UG Piping Relocations and Installation / Foundations / Ash Bunker)	4.2	Sep-22	Feb-23
T-BA-C-492-M-CON-99	Str / Mech (AG Utility Relos / Conv Steel / Eqpmnt Install / BoP Piping)	5.6	Oct-22	May-23
T-BA-C-492-E-CON-80	Elec / I&C (Conduit & Cable Tray Install / DCS Eqpmnt Install / Pull Power and Control Cabling and Terminate)	4.4	Dec-22	May-23
Construction Unit 1		7.8	Sep-22	Jun-23
T-BA-C-492-C-CON-82	Civil (UG Piping Relocations and Installation / Foundations / Ash Bunker)	4.8	Sep-22	Feb-23
T-BA-C-492-M-CON-109	Str / Mech (AG Utility Relos / Conv Steel / Eqpmnt Install / BoP Piping)	6.5	Oct-22	Jun-23
T-BA-C-492-E-CON-90	Elec / I&C (Conduit & Cable Tray Install / DCS Eqpmnt Install / Pull Power and Control Cabling and Terminate)	8.5	Dec-22	Jun-23
BA System Start-Up & Commissioning		1.8	Apr-23	Jun-23



Current Bar Labels Summary
◆ Milestone

EXHIBIT 6

Southern Company

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May 30, 2023

Electronically submitted via www.regulations.gov

Attn: Docket ID EPA-HQ-OW-2009-0819

RE: Comments of The Southern Company on Supplemental Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category; Proposed Rule; 88 FR 18824 (Mar. 29, 2023).

Mr. Richard Benware,

The Southern Company respectfully submits the following comments in response to the U.S. Environmental Protection Agency's (EPA) March 29, 2023 Federal Register notice seeking public input on EPA's proposed rulemaking to revise the effluent limitations guidelines and standards (ELGs) for the steam electric power generating point source category. These comments are submitted on behalf of The Southern Company and its subsidiaries, Alabama Power Company, Georgia Power Company, Mississippi Power Company, Southern Nuclear Company and Southern Power Company.

The Southern Company appreciates the opportunity to comment on this proposed rulemaking. In our comments, we present ways in which EPA can finalize a rulemaking in a way that helps to ensure the delivery of clean, safe, reliable and affordable energy to customers. Where possible, we provide real examples of our operating experience to illustrate the benefits of any suggested modifications.

We look forward to engaging constructively with EPA on this important rulemaking. If you have any questions about these comments or need additional information, please do not hesitate to contact me or Donna Hill at 205-257-5234 or dbhill@southernco.com.

Sincerely,

Jeffrey A. Burleson



Comments of The Southern Company on
Environmental Protection Agency Proposed Rule;
Supplemental Effluent Limitations Guidelines and Standards for the
Steam Electric Power Generating Point Source Category

88 Fed. Reg. 18,824 (Mar. 29, 2023)
Docket ID No. EPA-HQ-OW-2009-0819

May 30, 2023

EXECUTIVE SUMMARY

The Southern Company[1] (Southern or the Company) is committed to building the future of energy for the advancement of our customers and communities. Through industry-leading innovation and a commitment to a net zero future, we are delivering the customized sustainable and resilient energy solutions our customers and communities require to help drive growth and prosperity. Our uncompromising values put the needs of those we serve at the center of everything we do. With these values in mind, we are focused on transitioning our generating fleet to net zero greenhouse gas emissions and making the necessary related investments in our transmission and distribution grids, while maintaining reliability and affordability for our customers.

The Southern Company system's compliance plan for the 2020 ELG Reconsideration Rule[2] (2020 Rule) reflects our continued commitment to comply with all environmental rules and regulations, to responsibly transition our system's generating fleet, and to continue to research and develop emerging wastewater treatment technologies. The 2020 Rule, and the associated compliance options, are now key components to facilitate the orderly fleet transition for both replacement generation resources as well as necessary transmission project completion. However, in the midst of the energy transformation that is underway at Southern, the U.S. Environmental Protection Agency's (EPA's or the Agency's) recently proposed

[1] The Southern Company is a holding company that conducts its business through its subsidiaries, accordingly, unless the context otherwise requires, references in this letter to The Southern Company's operations, such as generating activities, refer to those operations conducted through its subsidiaries.

[2] 85 Fed. Reg. 64,650 (Oct. 13, 2020).

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Supplemental ELG Rule[3] ("the proposal" or "the 2023 Rulemaking") threatens to disrupt the orderly fleet transition by increasing risks to reliability while burdening customers with undue costs. EPA has heavily underestimated both the costs and necessary timeframes for complying with this proposed rule, which will result in a tremendous cost burden to customers and negative impacts to our ability to provide clean, safe, reliable, and affordable energy to customers.

The impacts of this proposed rule are apparent when considering the cascading and unaccounted for impacts to Georgia Power's Plant Bowen. Plant Bowen, located in Cartersville, Georgia serves as a key dispatchable reliability asset for the Metro Atlanta and North Georgia load center. EPA's proposed Best Available Technology Economically Achievable (BAT) (membrane filtration) for flue gas desulfurization (FGD) wastewater treatment has not been adequately demonstrated as suitable for all plants and raises significant feasibility concerns for Plant Bowen due to site-specific characteristics. Notwithstanding those concerns, not only would installation of membrane filtration at Plant Bowen increase the capital costs of the ELG compliance strategy by hundreds of millions of dollars and eliminate the environmentally friendly beneficial use of operational fly ash at the site, but EPA's basis for how facilities would meet the zero liquid discharge (ZLD) requirement could also result in unacceptable consequences for operations, such as the forced operation of the plant just to prevent discharge of treated permeate.

Further, the 2029 compliance deadline does not allow for sufficient time to complete necessary transmission and replacement generation to consider alternatives to installation of controls. Whereas Georgia Power has anticipated the eventual retirement of Plant Bowen by the end of 2035, Plant Bowen remains critical to

[3] Supplemental Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category, 88 Fed. Reg. 18,824 (Mar. 29, 2023).

maintaining electric service in north Georgia during the time that both replacement generation and new transmission projects are being completed. Through the state regulatory framework in Georgia, the Public Service Commission (PSC or the Commission) governs generation resource decisions and approves the transmission plans to ensure the utility can meet its obligation to serve its customers. Georgia Power is required under Georgia law and PSC regulation to complete comprehensive and long-term integrated resource planning every three years. This thorough and fully litigated process ensures decisions are made in the best interest of customers but necessarily takes time. A compliance deadline of 2029 does not allow for the appropriate time to complete these necessary projects, and the proposed rule does not offer the appropriate flexibility to alleviate the disparate costs to aging units and accommodate the time necessary to replace generation.

These impacts are not limited to Plant Bowen. Alabama's Plant Miller has already proceeded with the installation of EPA's 2020 Rule BAT and has been named by EPA in this rulemaking as an "early adopter" of the 2020 Rule. Yet, the early adopter subcategory allows plants like Miller with the option to retire earlier than anticipated, as opposed to recognizing the environmental benefits of having operated a more stringent FGD wastewater treatment plant and allowing the plant to both maximize the environmental benefits of EPA's recently established BAT and allow for adequate time to recover costs of these investments and properly evaluate the impacts of other potentially significant power sector rulemakings before abandoning the biological treatment system for EPA's newly proposed membrane technology. This membrane technology is significantly more expensive than EPA has estimated, and EPA has not fully evaluated the extent of non-water quality impacts, including the elimination of beneficial fly ash use to the local concrete market and the resulting negative impacts on economic development and infrastructure projects dependent on this resource.

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In addition to EPA's revisions to effluent limitations for both bottom ash transport water (BATW) and FGD wastewater, EPA is also proposing to establish new effluent limits for both legacy wastewater (LWW) and combustion residual leachate (CRL). EPA has solicited comments for a multitude of compliance options for these waste streams, some of which are unnecessarily complicated and do not reflect current practices that are already in place to treat these waste streams. The Southern Company's electric operating companies are currently dewatering ash ponds across the system under state regulatory oversight with treatment that is protective of state water quality standards. These treatment system configurations are very site-specific and are integral to an efficient and protective closure process. We are concerned that finalizing the rule as proposed could negatively impact the progress of ash pond closures being conducted to comply with aggressive timelines under the coal combustion residuals (CCR) Rule[4] (CCR Rule).

While the Company is committed to installation and operation of wastewater treatment under the ELG Rule, the realities of cost and reliability concerns in serving our customers cannot be ignored. We encourage EPA to finalize a Supplemental ELG Rule that can protect the environment, promote resiliency and reliability of the electric power system, and help to alleviate a significant cost burden to customers. In these comments, The Southern Company provides detailed review and recommendations to EPA regarding the following issues:

EPA's failure to pause implementation of the 2020 Rule has created important reliance interests that need to be protected:

- EPA's failure to pause implementation of the 2020 Rule has created important reliance interests that need to be protected. EPA should acknowledge the consequences to customers of requiring

[4] 80 Fed. Reg. 21,301 (Apr. 17, 2015).

continued compliance with its recently finalized 2020 Rule while it simultaneously proceeded with its revision to more costly compliance options that render certain 2020 compliance investments obsolete. To address these interests more adequately, EPA must either reject its newly proposed BAT for FGD wastewater or finalize a rule with appropriate time to comply with the new BAT and flexibilities for aging units to either comply with the new BAT, retire or repower under an appropriate timeframe.

EPA's proposed BAT for FGD wastewater:

- As EPA correctly concluded in 2015 and 2020 and as has been confirmed by The Southern Company wastewater treatment experience and research results provided to EPA, membrane filtration is still not the BAT and ZLD is not a realistic effluent limit for FGD wastewater across the industry.
- As was done in both 2015 and 2020, we urge EPA to again reject membrane filtration and paste encapsulation as industry BAT for FGD wastewater. EPA has not adequately demonstrated that the newly proposed BAT is feasible beyond a limited number of plants and has not adequately considered specific data and information submitted previously to the Agency explaining why the technology is not suitable at every plant. Furthermore, EPA's proposed BAT for FGD wastewater imposes substantial and significantly underestimated new costs to customers and renders costly investments made in EPA's 2020 Rule as obsolete in as little as four years after they will have been installed. Additionally, EPA has not adequately considered the significant non-water quality impacts associated with the proposed BAT, particularly the negative consequence of eliminating

beneficial use of operational fly ash at both Alabama Power's Plant Miller and Georgia Power's Plant Bowen.

Compliance timeframes:

- If EPA finalizes the proposed BAT despite the concerns outlined above, we urge EPA to extend the late applicability date to December 31, 2032, to account for the additional time needed for site-specific planning requirements and/or research and development of the emerging technology. Requiring compliance by no later than December 31, 2029, would prematurely obsolete the biological treatment systems installed to comply with the 2020 Rule and increase cost impacts to customers by shortening the useful life of the equipment. Furthermore, EPA should maximize the environmental benefits associated with these investments by extending the date to comply with any new BAT.

Retirement and repowering subcategories:

- Existing Permanent Cessation of Coal Combustion (PCCC) by 2028 Subcategory: EPA should maintain the existing PCCC by 2028 subcategory without modification. As mentioned, the 2020 Rule PCCC by 2028 subcategory is now a key component of our planning process to transition the fleet and modifications to this subcategory, such as any new or more stringent requirements, could disrupt the orderly fleet transition.
- *New* PCCC by 2035 Subcategory: If EPA finalizes the proposed BAT despite the aforementioned concerns, EPA should create a new PCCC by 2035 subcategory that allows facilities the option to continue operating under the 2020 Rule BAT and opt to either comply with the new BAT by December 31, 2032, or retire by December 31, 2035. This subcategory would allow facilities that are nearing retirement the appropriate timing and opportunity to alleviate unnecessary cost burdens

to customers and ensure continued reliable and resilient delivery of energy while replacement generation and associated transmission is completed.

- Early Adopter Subcategory: If EPA finalizes the proposed BAT, EPA should make key modifications to the early adopter subcategory to ensure an equitable treatment of those that do and should qualify as early adopters.
    - First, EPA should modify the subcategory criteria cutoff date and expand the definition of early adopter to include those facilities that have made financial commitments to compliance with the 2020 Rule.
    - Second, EPA should not require that early adopters retire by December 31, 2032, but should instead allow early adopters to comply with the new BAT by December 31, 2032, or retire by December 31, 2035.

Legacy Wastewater and Combustion Residual Leachate:

- Legacy Wastewater (LWW): EPA has proposed several changes to LWW requirements in the proposal, including subdividing LWW into new categories, new definitions, and requiring different management requirements for the new categories. While we support best professional judgment (BPJ) limits for LWW, we also urge caution with any revision to the LWW requirements or the imposition of permitting constraints that could impose unnecessarily costly or stringent requirements or that could complicate, delay, or derail ongoing dewatering and closure activities required by the CCR Rule.
- Combustion Residual Leachate (CRL): Southern does not object to the proposed BAT limits for arsenic and mercury for this waste stream but believes EPA must constrain the scope of regulated CRL to that which is collected from engineered leachate collection systems and then discharged via surface outfalls from active landfills at active generating plants. Subjecting numerous

unidentified and uncharacterized sources of water to an improper regulatory definition completely unbalances any underlying determinations or assumptions of cost-effectiveness. This rulemaking should not establish effluent limits or permitting requirements for functional equivalent discharges of CRL because unlined landfills and surface impoundments are not point sources.

In assessing the potential impacts of the proposed Supplemental ELG Rule, Southern Company's focus is on managing the transition of our generation fleet in a way that protects both the environment and the best interests of our customers. We believe the suggestions provided herein are critical to maintaining clean, safe, reliable, and affordable energy for the communities we serve as we transition to a net-zero future.

Appellate Case: 24-2123 Page: 11 Date Filed: 07/26/2024 Entry ID: 5417837

I. INTRODUCTION 13

A. The Southern Company is committed to an orderly fleet transition. 13

B. The 2020 ELG Reconsideration Rule provided robust wastewater treatment while facilitating orderly fleet transition to net zero greenhouse gas emissions. 14

C. The 2023 proposed rule fails to consider the time and cost commitments companies made based on the prior ELGs. 15

D. EPA can and should finalize solutions that embrace evidence-based decision making, implement robust and proven wastewater treatment, and avoid unnecessary disruption to orderly fleet transition. 16

II. EPA'S DECISION TO CONTINUE COMPLIANCE WITH THE 2020 RECONSIDERATION RULE DURING THIS RULEMAKING PROCESS CREATED IMPORTANT RELIANCE INTERESTS THAT NEED TO BE PROTECTED. 18

A. EPA should have paused or delayed implementation of the 2020 Rule, but did not, thereby creating reliance interests that need to be protected now. 20

1. EPA needs to consider reliance interests. 20

2. NPDES permittees, including The Southern Company facilities, have significant reliance interests. 22

B. EPA should address ongoing 2020 compliance obligations. 23

1. EPA needs to explain its rationale for not delaying compliance pending the outcome of this rulemaking. 23

2. EPA needs to acknowledge the reality of its decision to not pause or delay implementation of the 2020 Rule. 25

3. EPA needs to consider disparate costs associated with its proposal. 27

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I. INTRODUCTION

A. The Southern Company is committed to an orderly fleet transition.

The Southern Company is committed to reducing our greenhouse gas (GHG) emissions to provide our customers and communities with a clean energy future. Southern has set an interim goal to reduce direct system-wide GHG emissions by 50% by 2030 (from 2007 levels) and a long–term goal of net zero emissions by 2050. To reach our net zero by 2050 GHG goal, Southern is focused on transitioning our generating fleet and making the necessary related investments in our transmission and distribution grids, while maintaining reliability and affordability for our customers.

Southern continues to reduce the number of generating units in our coal fleet, lowering emissions, and retiring uneconomic resources. When considering the retirements and conversions that have already been implemented by our electric operating companies, as well as expected future retirements or conversions that have been filed with state environmental and/or regulatory agencies, we currently expect to have just six coal units[5] remaining in our generating fleet with a nameplate capacity of less than 3,000 MWs by the end of 2035. The addition or retirement of generation resources, transmission capacity, and expansion plans for load growth are closely related, and our electric operating companies must consider these elements together in their comprehensive planning processes within their respective state regulatory constructs.

[5] Miller Units 1-4 and Scherer Units 1-2.

B. The 2020 ELG Reconsideration Rule provided robust wastewater treatment while facilitating orderly fleet transition to net zero greenhouse gas emissions.

Sound environmental policies play a critical role, not only in protecting our environment, but also in maintaining a resilient and reliable electric power system. The EPA and the Department of Energy (DOE) recently issued the Joint Memorandum on Interagency Communication and Consultation on Electrical Reliability, which stated, "With the sound application of existing authorities and policy tools, the EPA and DOE can continue to support the reliability of the electric power system."[6] The Southern Company agrees that there are solutions EPA can implement through environmental rules that can protect the environment, promote resiliency and reliability of the electric power system, and help to alleviate a significant cost burden to customers.

As an example, the 2020 Rule, and the associated compliance options, are key components to facilitate the orderly fleet transition for both replacement generation resources and necessary transmission project completion. In 2020 and 2021, the Company's planning processes were used to evaluate the 2020 Rule and, as a result of that evaluation, we determined that the rule would impact most of the coal-fired generating units across The Southern Company system. Notices of Planned Participation (NOPPs) were filed with state environmental agencies in October 2021 indicating our intent to repower two coal units with natural gas

[6] DOE & EPA, Joint Memorandum on Interagency Communication & Consultation on Electric Reliability, at 2 (Mar. 9, 2023).

and retire 10 coal-fired generating units on or before December 31, 2028, in accordance with the 2020 Rule's PCCC by 2028 subcategory.[7]

In addition to the retirements and repowering, two units at Georgia Power's Plant Scherer opted into the Voluntary Incentives Program (VIP) option for FGD wastewater[8] and Alabama Power's Plant Miller and Georgia Power's Plant Bowen planned to install the 2020 Rule's BAT for FGD wastewater - chemical precipitation followed by biological treatment. Alabama Power's Plant Miller has installed and is currently operating the 2020 BAT, with an NPDES permit applicability date of December 31, 2023. Georgia Power's Plant Bowen NPDES permit requires compliance with the 2020 Rule's generally applicable limits; and the facility is on schedule and expects to achieve compliance no later than December 31, 2025.

C. The 2023 proposed rule fails to consider the time and cost commitments companies made based on the prior ELGs.

The Southern Company system's compliance with the 2020 Rule reflects our continued commitment to comply with all environmental rules and regulations, to responsibly transition our system's generating fleet to net zero GHG emissions, and to research and develop emerging wastewater treatment technologies. If finalized as proposed, the 2023 proposed rule will be the third iteration of effluent limitations guidelines for the steam electric industry sector promulgated in less than ten years. During the prior two rulemakings,

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[7] Formal requests for retirement or natural-gas repowering related to these plants were also filed with state utility regulators and approvals have already been received to reduce the total number of coal-fired generating units to 10. In prior filings, Georgia Power requested to retire Plant Bowen Units 1&2 by 2028 and expects these requests to be considered in future regulatory proceedings.

[8] Given extensive research efforts, unique low flow rates, low chlorides, and total dissolved solids, and an associated viable permeate recovery rate, Georgia Power was able to file a NOPP for the VIP at Plant Scherer Units 1-2. This submittal was made prospectively (which was necessary due to the deadlines for submitting NOPPs), as studies are ongoing with regards to brine management and disposal.

EPA acknowledged the significant cost and resource burden required to investigate, design, construct, and optimize the massive and complex wastewater treatment systems necessary for compliance with the ELGs and took steps to mitigate unnecessary costs to facilities and customers that could be incurred during the rulemaking process. By contrast, in this third rulemaking process, EPA has continued to require facilities to comply with the 2020 Rule, even though the Agency has known since 2021 that it would promulgate more stringent limits that will apply to these same facilities within a short timeframe. EPA's failure to pause compliance timeframes for the 2020 Rule during the pendency of this rulemaking unfairly prejudices our good faith efforts to implement and comply with the regulatory options presented by EPA less than three years ago in the 2020 Rule.

D. EPA can and should finalize solutions that embrace evidence-based decision making, implement robust and proven wastewater treatment, and avoid unnecessary disruption to orderly fleet transition.

We encourage EPA to implement environmental rules that can protect the environment, promote resiliency and reliability of the electric power system, and help to alleviate a significant cost burden to customers. As discussed in detail in our comments, we strongly encourage EPA to consider the following actions when finalizing the 2023 proposed rule:

- **BAT for FGD Wastewater:** As EPA correctly concluded in 2015 and 2020, and as our recent engagement with EPA[9] and detailed comments here will illustrate, membrane filtration is still not the BAT and ZLD is not a realistic effluent limit for FGD wastewater across the industry. EPA should

[9] *See* Letter from Donna Hill, Southern Company Services, Inc. to Robert K. Wood, Director, Office of Water, Engineering & Analysis Division (Apr. 1, 2022).

acknowledge the overwhelming evidence against establishing membrane filtration as BAT for FGD wastewater in the steam electric category and once again reject membrane filtration as BAT for the industry.

- **Fleet Transition:** We strongly support the continued availability of both the PCCC by 2028 subcategory and the VIP option as they were finalized in the 2020 Rule to minimize any potential disruption to our cost-effective, orderly fleet transition planning and execution and to minimize any further disparate cost impacts.
- **Compliance Timeframes:** If EPA finalizes the proposed BAT for FGD wastewater, EPA should also finalize compliance implementation schedules that are harmonized with other power sector rulemakings and establish subcategories to alleviate the disparate costs on coal units nearing retirement, thus promoting both resiliency and reliability. Specifically, our comments present solutions for EPA to consider for harmonizing the compliance timeframes in this rulemaking with those recently proposed in the greenhouse gas rulemaking. Our comments also suggest changes to EPA's proposed "early adopter" subcategory and request the establishment of additional subcategories.
- **Legacy Wastewater (LWW):** As a general matter, the Company urges caution with any revision to the LWW requirements that could complicate, delay, or derail ongoing dewatering and closure activities required by the CCR Rule. We support a BPJ permitting approach that takes existing treatment practices and site-specific factors into appropriate consideration without defaulting to the most stringent treatment technology available on site. EPA should not subcategorize LWW separated by time or define surface impoundment wastewaters based on the location of the water above the CCR solids.
- **Combustion Residual Leachate (CRL):** The Company does not object to EPA's proposed BAT selection (chemical precipitation) for CRL. However, EPA should constrain the scope of regulated CRL to that which is collected from engineered leachate collection systems and then discharged via surface water outfalls from active landfills at active generating plants. This rulemaking should not

establish effluent limits or permitting requirements for functional equivalent discharges of CRL for an array of reasons, but most importantly because unlined landfills and surface impoundments are not point sources. More stringent technologies are not cost-effective and pose significant operating, maintenance, and economic burdens to an operating plant, especially after a plant's retirement.

We appreciate the EPA's consideration of these comments, and we look forward to constructive engagement moving forward.

II. EPA'S DECISION TO CONTINUE COMPLIANCE WITH THE 2020 RECONSIDERATION RULE DURING THIS RULEMAKING PROCESS CREATED IMPORTANT RELIANCE INTERESTS THAT NEED TO BE PROTECTED.

EPA first established ELGs for the steam electric industry in 1974, 1977, and 1982. Then, 35 years later, EPA promulgated comprehensive and significant revisions to the then-existing ELGs to reflect technology changes in the industry sector over the three prior decades (2015 Rule)[10], as well as widespread implementation of air pollution controls under the Clean Air Act (CAA). Litigation followed the 2015 Rule, with some effluent limits being vacated by the Fifth Circuit Court of Appeals[11] and others being reconsidered by EPA.[12] EPA twice postponed compliance deadlines for other portions of the 2015 Rule,

[10] 80 Fed. Reg. 67,838 (Nov. 3, 2015) ("2015 Rule").

[11] *Sw. Elec. Power Co. v. EPA*, 920 F.3d 999 (5th Cir. 2019).

[12] 85 Fed. Reg. 64,650 (Oct. 13, 2020).

first during the pendency of the Fifth Circuit litigation and again while the Agency evaluated whether to reconsider some portions of the 2015 Rule.[13]

In October 2020, EPA's updated effluent limits for two waste streams (BATW and FGD wastewater) became effective.[14] Three months after the 2020 Rule went into effect, EPA announced it would be reconsidering every agency action taken by the prior administration. In July 2021, EPA announced that it was initiating a rulemaking to "strengthen" the effluent limits promulgated in the 2020 Rule.[15] At the same time, EPA announced that it would not be pausing the effectiveness of the 2015 or 2020 Rules or the associated 2023 and 2025 compliance deadlines.[16] In other words, EPA clearly communicated that facilities were to continue complying with the 2020 Rule while EPA promulgated a new "more stringent" rule that EPA indicated would be based on membrane treatment technology.

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[13] *See* 82 Fed. Reg. 19,005, 19,005 ("Apr. 25, 2017) ("In light of the capital expenditures that facilities incurring costs under the Rule will need to undertake in order to meet the compliance deadlines for the new, more stringent limitations and standards in the Rule. . . the Agency finds that justice requires it to postpone the compliance dates of the Rule that have not yet passed, pending judicial review."); *see also* 82 Fed. Reg. 43,494, 43,496 (Sept. 18, 2018) ("This will prevent the potentially needless expenditure of resources during a rulemaking that may ultimately change the 2015 Rule in these respects.").

[14] 85 Fed. Reg. 64,650 (Oct. 13, 2020) ("2020 Rule").

[15] EPA, EPA Announces Intent to Bolster Limits on Water Pollution from Power Plants (July 26, 2021), *available at* https://www.epa.gov/newsreleases/epa-announces-intent-bolster-limits-water-pollution-power-plants#:~:text=EPA%20Announces%20Intent%20to%20Bolster%20Limits%20on%20Water%20Pollution%20from%20Power%20Plants,-July%2026%2C%202021&text=WASHINGTON%20%E2%80%93%20Today%2C%20the%20U.S.%20Environmental,use%20steam%20to%20generate%20electricity.; *see also* 86 Fed. Reg. 41,801, 41,802 (Aug. 3, 2021) ("While the Agency undertakes this new rulemaking, facilities will continue to be subject to the requirements of the 2015 Rule, as amended by the 2020 Rule, which are currently effective. As a result, the pollutant reductions accomplished by the existing Rules will occur while the Agency engages in rulemaking to consider more stringent requirements.").

[16] EPA, *supra* note 15 ("While the agency pursues this new rulemaking process to strengthen water pollution requirements for coal power plants, the current regulations will be implemented and enforced.").

As discussed in more detail below, EPA's current proposal *significantly* changes many aspects of the 2020 Rule. Because EPA never paused or delayed implementation of the 2020 Rule, EPA's actions created important reliance interests for industry that need to be meaningfully addressed, and protected, as part of the 2023 Rulemaking.[17]

A. EPA should have paused or delayed implementation of the 2020 Rule, but did not, thereby creating reliance interests that need to be protected now.

When EPA first announced in 2021 that it was planning to make the ELG rule more stringent than the 2020 Rule, it should have paused or delayed the then-applicable compliance dates to prevent significant and unnecessary expenditures. Instead, EPA chose to continue requiring compliance with the 2020 Rule. As a result, many facilities made significant investments in biological treatment systems that will now be rendered obsolete through the 2023 Rulemaking. To avoid this outcome, EPA's final rule should include specific additional flexibilities that reflect the good faith efforts that have been undertaken to comply with the 2015 and 2020 Rules, and at a minimum, consider the costs associated with these continued efforts to comply with the rules in the Agency's BAT analysis.

1. EPA needs to consider reliance interests.

As a matter of both good public policy and procedural protections of the Administrative Procedures Act, EPA must consider how proposed rule revisions will affect the regulated community. For the 2023 Rulemaking, this means EPA must consider the impact to facilities that have already made—or are in the

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[17] *See Dep't of Homeland Sec. v. Regents of the Univ. of California*, 140 S. Ct. 1891, 1915 (2020) (the agency "*was* required to assess whether there were reliance interests, determine whether they were significant, and weigh any such interests against competing policy concerns." (emphasis in original)).

process of making—significant capital investments to comply with the 2020 Rule. In the preamble, EPA mentions the word "reliance" only three times and substantively only in a footnote where EPA states:

> EPA also recognizes that, while it may change policies based upon a reasoned explanation, where a prior policy has engendered serious reliance interests, those interests must be taken into account. FCC v. Fox Television Stations, Inc., 556 U.S. at 515 (citation omitted). EPA has taken reliance interests into account in this rulemaking, as is clear from EPA's proposal in Section VII.C.4 of this preamble, below, to create a new subcategory for early adopters who relied on certain of EPA's past determinations. EPA also notes that no NPDES permittee has certainty of its limitations beyond its 5-year NPDES permit term, as reissued permits must incorporate any newly promulgated technology-based limitations as well as potentially more stringent limitations necessary to achieve water quality standards. See 40 CFR 122.44(a) & (d).[18] 88 FR 18839, fn. 23.

With this footnote, EPA seems to concede that it only narrowly considered reliance interests, and only those asserted by facilities that qualify for the proposed category for early adopters (those that can demonstrate compliance with either the 2015 or 2020 Rule by March 29, 2023). However, EPA readily admits that only 15 out of the 69 to 93 potentially affected facilities would be eligible for its proposed subcategory.[19] For all other affected facilities, EPA does not appear to have considered reliance interests at all.

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[18] 88 Fed. Reg. at 18,839 n.23.

[19] 88 Fed. Reg. at 18,833, 18,859, Table VII.

Instead, EPA downplays those interests on grounds that the other affected facilities are subject to NPDES permits that are subject to reissuance proceedings every five years. However, in reality, NPDES permits are routinely subject to administrative extensions that can last for years due to changing regulatory landscapes, program staffing shortages, and other complications. EPA's statement also ignores the fact that it typically takes decades for the Agency to revisit and promulgate updated effluent limitations guidelines for a point source category (as evidenced by the 33 years between the 1982 and 2015 final rules). Even ignoring these practicalities, EPA still must consider the effect of proposed changes on permittees. Indeed, this is why the NPDES permit program includes a provision for compliance schedules to enable permittees to take the steps necessary to come into compliance with newly imposed limits or conditions.[20]

2. NPDES permittees, including The Southern Company facilities, have significant reliance interests.

The Southern Company system's facilities subject to the steam electric ELGs have accrued significant reliance interests based on EPA's ongoing directive to comply with the 2020 Rule. NPDES permittees, including Georgia Power's Plant Bowen, which have not yet *achieved* compliance with the FGD wastewater effluent limits in the 2020 Rule, nonetheless have permit conditions that require compliance by a date certain (no later than December 31, 2025, for FGD wastewater). To do so, it must install a biological treatment system and begin optimization by the beginning of 2025. In addition, many permittees also face interim milestone deadlines as their facilities approach the 2023 and 2025 deadlines. To stay on track to meet these deadlines, permittees must make significant investments of resources, including for research, development, planning, design, contracting, procurement, construction and in many cases complex and

[20] *See* 40 C.F.R. § 122.47.

protracted state utility regulatory approval. Even facilities that do not yet have permit conditions reflecting the 2020 Rule still may have made binding commitments to meet the rule limits and deadlines through submittals to regulatory agencies, including the required NOPPs.

In the 2023 Rulemaking, EPA appears to have made little effort to investigate costs incurred by those facilities who are on track to – but have not yet achieved – compliance with the 2020 Rule.[21] Given that a final rule will likely not be issued until mid-2024 at the earliest, the inescapable reality is that many permittees who are still in the process of implementing their compliance plans will have no choice but to fully comply with the 2020 Rule *and then also* comply with EPA's new final rule within just another four years (at the most). EPA's final rule should avoid this outcome to achieve the Agency's objectives and ensure that the rule is durable.

B. EPA should address ongoing 2020 compliance obligations.

In addition to the reliance interests described above, EPA needs to consider a number of other important aspects of the compliance challenges imposed on the industry sector, including the Agency's decision not to pause or delay implementation of the 2020 Rule during its lengthy supplemental rulemaking.

1. EPA needs to explain its rationale for not delaying compliance pending the outcome of this rulemaking.

As explained above, when EPA twice delayed compliance dates for the 2015 Rule, the Agency noted the significant capital and operation and maintenance costs that go into complying with an ELG. The Agency

[21] *See, e.g.*, 88 Fed. Reg. at 18,859 (comparing "early adopters" under the proposal with the rest of the affected facilities that EPA claims "have avoided incurring any cost for as long as possible . . . .").

further found that postponing compliance "will prevent the potentially needless expenditure of resources" because the applicable effluent limits may change as a result of the Agency's rulemaking.[22] EPA should have done the same here due to the significant (and potentially misdirected or unnecessary) costs that affected facilities will incur if they are required to first comply with the 2015 and 2020 Rules and then also comply with new, more stringent requirements based on entirely different and unproven technology underpinnings.

In July 2021, EPA announced it would be revising the steam electric ELG to be "more stringent," likely based on membrane technology, but required facilities to continue investing in, designing, and building biological treatment to meet the requirements of the 2020 Rule. The explanation in EPA's press release was that "the agency's approach will secure progress made by the 2015 and 2020 Rules while the Agency undertakes a new rulemaking to consider more stringent requirements."[23]

In the 2023 Rulemaking, EPA reiterates the requirement that facilities build biological treatment to achieve compliance with the 2020 Rules, while simultaneously proposing that membrane-based ZLD systems must be installed by no later than December 31, 2029. EPA's proposal touts the water quality improvements that will result from building biological treatment during the rulemaking process,[24] but does not acknowledge the costs associated with installing two different treatment systems within a few years' time, as it did in 2017 and 2018, and instead attempts to recast its previous rationale for delaying compliance. EPA now claims that its previous decisions to delay compliance deadlines "made sense at the time because EPA had

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[22] *See* 82 Fed. Reg. at 43,494 (Sept. 18, 2018); *see also* 82 Fed. Reg. at 19,005.

[23] EPA, *supra* note 15.

[24] Importantly, EPA does not seem to grasp that many systems will largely be only in the procurement and construction phase of the project during this ongoing rulemaking process.

received new information in petitions suggesting that the 2015 Rule limitations could not be met with the 2015 BAT technology basis."[25] The proposal makes no mention of EPA's prior conclusions regarding significant costs and potentially needless expenditures.

We urge EPA to acknowledge that its previous rationale for delaying compliance was driven by the significant costs facilities and customers would incur and apply that same rationale here.

2. EPA needs to acknowledge the reality of its decision to not pause or delay implementation of the 2020 Rule.

As explained in detail above, EPA has been clear since July 2021 that it would not pause or delay applicability of the 2020 Rule while it undertook this new rulemaking. The proposal is similarly clear that "permittees must meet applicable permit limitations as soon as possible."[26] Moreover, in the proposal, EPA reaffirms that permitting authorities must include the 2020 limits in new or modified permits and affected facilities must comply as soon as possible.[27] EPA instructs state permitting authorities that they should not establish 2020 Rule compliance deadlines that are "anything other than as soon as possible for the selected technology"[28] and asserts that "anything but steadfast implementation of the current 2020 rule limitations at this time is not warranted."[29] We urge EPA to revisit this stance. By way of example, on December 1, 2021, Georgia Power's Plant Bowen's NPDES permit was reissued with enforceable conditions requiring

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[25] 88 Fed. Reg. at 18,886.

[26] *Id.*

[27] *Id.*

[28] *Id.*

[29] *Id.*

the facility to comply with the 2020 FGD wastewater limits by no later than December 31, 2025. Thereafter, Plant Bowen initiated a design, engineering and construction effort to comply with the 2020 Rule at a significant cost and has already incurred approximately $50 million to date. Depending on when a final rule is issued, Plant Bowen's current compliance costs will continue to be incurred by an additional $30-40 million, which will represent nearly all installation and capital costs of the system. Unfortunately, this reality is at odds with EPA's claim that most facilities that have not already complied with the 2020 Rule "have avoided incurring any cost."[30]

If the rule is finalized, as proposed, in 2024, Plant Bowen will have to make the difficult choice of either: 1) abandoning on-going efforts to comply with the 2020 Rule (including the nearly $110 million in investment it will have made toward 2020 Rule compliance) and seek a permit modification to immediately begin planning to construct a membrane-based ZLD system by December 31, 2029; or 2) complete installation and optimization of the biological treatment technology by December 31, 2025 as required by its NPDES permit; immediately initiate the planning, financing, and design process for another major facility modification with a proposed deadline of December 31, 2029; and operate the biological treatment system for only a few years before being decommissioned and replaced with a membrane treatment system required to be operational in 2029. EPA has not adequately considered the very real cost consequence of the proposed rule to utility customers.

Although it is true that facilities could have selected the VIP option under the 2020 Rule, which would also require membrane technology, this was not a realistic option for many facilities based on site-specific factors. EPA may state that the Agency repeatedly communicated that membranes would be BAT (long

[30] *Id*. at 18,859.

before EPA's rulemaking would be completed) so there is no unfair surprise to the regulated community. If that is the Agency's position, it should say so, and it should explain how an informal statement should be taken with the same regard as a final rule and how such a statement is not predetermining the outcome of a rulemaking. Unless remedied in the final rulemaking, this set of circumstances created by EPA will result in hundreds of millions of dollars in stranded costs to customers that facilities like Plant Bowen will incur as a result of EPA's decision to require compliance with the 2020 Rule while knowing it will establish new, far more stringent limits in a few short years. Moreover, as noted above, regulated electric utilities cannot make compliance decisions based on non-binding communications from its regulators separate from actual rule requirements.

3. EPA needs to consider disparate costs associated with its proposal.

Any facility that achieves compliance with the 2020 Rule FGD wastewater effluent limits will suffer disparate costs, with those achieving compliance in 2023 and beyond the most impacted. As EPA explains, "amortization periods shorter than eight years may lead to disparate costs."[31] EPA even provides an example that, where an applicant provides site-relevant information that its FGD wastewater biological treatment system can achieve compliance with the 2020 Rule by 2023, "it would not be appropriate" to establish a compliance date any later, even considering the ongoing rulemaking.[32] Using EPA's example, the facility that achieves compliance with the 2020 Rule in 2023 will still be subject to the next iteration of the rule (anticipated in 2024) which is expected to require compliance no later than December 31, 2029.

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[31] *Id.* EPA's eight-year amortization period is short-sighted. It ignores that these treatment technologies typically have a life-span of 20+years and that the premature abandonment of them also leads to disparate costs—both for utilities (especially those that do not engage in cost recovery) and, more importantly, for ratepayers that will be forced to prematurely incur the additional costs associated with installation of the new treatment system(s).

[32] *Id.* at 18,886.

This facility would have only a six-year amortization on its 2020 Rule compliance investment and thus would experience disparate costs.

EPA's only explanation is that it is prioritizing "progress toward eliminating discharges" and asserts this approach "is consistent with the Clean Water Act's (CWA's) structure of progressively more stringent limitations pushing technological advances over time."[33] EPA's explanation fails to reflect the likely large number of facilities that will suffer disparate costs based on the foregoing scenario. EPA also fails to explain why its proposed "early adopter" subcategory would only apply to facilities that are already in compliance by the time the proposal is published but would not apply to facilities that achieve compliance soon thereafter. EPA's disparate cost analysis applies equally to both groups of facilities, but the subcategory only applies to those who already achieved compliance.

Finally, EPA's cost estimate for its proposed rule assumes a baseline in which all affected facilities have already complied with the 2020 Rule, the cost of the proposal is added to that baseline, and the difference is the incremental additional cost to comply with the proposed rule. EPA's analysis is incomplete for many reasons but, most importantly, EPA's cost estimate amortizes the 2020 compliance costs over 20 years.[34] This does not present the true cost of mandating compliance with the 2020 Rule as soon as possible, and then mandating compliance with a new rule six or fewer years later. If EPA truly expects affected facilities to comply with the 2020 Rule, and then comply with new final requirements in 2024, it should properly apply an amortization of four to six years for those costs, not 20 years.

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[33] *Id.*

[34] *Id.* at 18,863.

III. EPA HAS NOT DEMONSTRATED THAT MEMBRANE FILTRATION-BASED ZLD TREATMENT IS BAT FOR FGD WASTEWATER

As EPA recognized in both the 2015 and 2020 Rules, membranes are neither technically nor economically available on a nationwide basis for treatment of FGD wastewater; and that fact has not changed over the past three years. The Southern Company has consistently communicated this fact in multiple communications[35] to EPA before the 2019 proposed ELG Reconsideration Rule (2019 proposal),[36] and as recently as April 1, 2022.[37] Even so, we recognized in 2019 that EPA left the door open for further analysis of membranes due to its suggestion that membranes could *become* BAT by the year 2028. In response, we stated in comments:

> Southern Company agrees membrane filtration is not BAT for FGD wastewater. However, we do not agree that this technology will be available in 2028 and think it is imprudent to make that determination almost nine years in advance. EPA's proposed prediction is not supported. Southern Company believes significant research is left to be done and that demonstration of this technology at commercial scale is needed prior to determining it will

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[35] *See, e.g.*, Letter from Susan Comensky, Vice President-Environmental Affairs, Alabama Power Company to Robert K. Wood, Director, Office of Water, Engineering & Analysis Division (Mar. 1, 2018); *see also* Letter from Susan Comensky, Vice President-Environmental Affairs, Alabama Power Company to Robert K. Wood, Director, Office of Water, Engineering & Analysis Division (Mar. 29, 2018); *see also* Letter from Susan Comensky, Vice President, Environmental Affairs, Alabama Power Company and from Mark Berry, Vice President, Environmental & Natural Resources, Georgia Power Company to Robert K. Wood, Director, Office of Water, Engineering & Analysis Division (Aug. 3, 2018).

[36] 84 Fed. Reg. 64,620 (Nov. 22, 2019).

[37] *See* Letter from Donna Hill, Southern Company Services, Inc., *supra* note 9.

> be technically feasible. Even if it is feasible, it may never be available nationwide due to site-specific constraints.[38]

Based on our operating experience, the Company maintains that the most suitable use of membrane filtration has been established –as the basis for the 2020 Rule's VIP option. An accurate, robust, and complete BAT analysis would demonstrate that membranes are not BAT, not only because of the very site-specific applicability of the technology, but also because of overall costs, disparate costs, the age of equipment involved, process changes required, and the significant non-water quality impacts that will result from implementing membrane treatment technology for FGD wastewater industry wide. EPA has also failed to explain how the CWA statutory factors informed the Agency's decision that biological treatment is not BAT, especially given the Agency's conclusion less than three years ago that biological treatment was BAT. We discuss these considerations in more detail below.

A. EPA failed to consider statutory factors in rejecting biological treatment as BAT.

The CWA requires EPA to consider specific statutory factors in making BAT determinations. Less than three years ago, EPA finalized a rule establishing BAT based on biological treatment. In the 2019 proposal and the 2020 Rule, EPA considered the statutory factors in selecting BAT *and also* in rejecting other

[38] Comment Letter from Jeffrey A. Burleson, Senior Vice President, Environmental and System Planning, Southern Company to Richard Benware, EPA, at 21 (Jan. 21, 2020) (Docket ID. No. EPA-HQ-OW-2009-0819-8457).

technologies as not BAT.[39] In the 2015 Rule, EPA also considered the statutory factors in rejecting technologies as not BAT.[40]

Now in 2023, as the Agency proposes to make a significant change in an ELG that is less than three years old, EPA only analyzes the statutory factors related to its selection of membrane-based ZLD as BAT. EPA does not consider or analyze any explicit statutory factors in its rejection of biological treatment as BAT. EPA's only explanation for rejecting biological treatment is that biological treatment captures fewer pollutants than the Agency's preferred option, membrane-based ZLD.[41] This analysis is insufficient to justify EPA's approach. Particularly given the history of the steam electric rule described above and the extremely short timeframe within which EPA has changed its mind on BAT, the Agency owes the public and the regulated community a full and complete analysis of why it is rejecting biological treatment, including analyzing the required statutory factors, not just an asymmetrical endorsement of its selected BAT.

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[39] *See, e.g.*, 84 Fed. Reg. at 64,632 ("LRTR is less costly than HRTR. Compared to the baseline of the 2015 rule, LRTR is estimated to save approximately $72 million per year in after-tax costs to industry. LRTR requires fewer process changes than HRTR. Compared to HRTR, LRTR installations are less complex and require fewer modifications to a facility's footprint."); *see also* 85 Fed. Reg. 64,650, 64,669 (Oct. 13, 2020) ("As authorized by section 304(b) of the CWA, which requires EPA to consider costs, as well as the discretion that the statute gives EPA to weigh the statutory factors, the Agency finds that, for this final rule, thermal technologies are not BAT due to the unreasonably high costs to industry. Given the high costs associated with thermal technology, and the fact that the steam electric power generating industry continues to face costs associated with several other rules, in addition to this rule, EPA is not establishing BAT limitations for FGD wastewater based on thermal technologies." (internal citaton omitted)).

[40] *See e.g.*, 80 Fed. Reg. at 67,852 ("The annual cost to the industry of limitations based on evaporation would be more than 2 and 1/2 times the cost to industry estimated for the final rule (after tax) (approximately $570 million more expensive than the final rule, on an annual basis, after tax). Given the high costs associated with the technology, and the fact that the steam electric industry is facing costs associated with several other rules in addition to this rule, EPA decided not to establish BAT limitations for FGD wastewater based on evaporation for all steam electric power plants.").

[41] 88 Fed. Reg. at 18,843-44.

This is especially true given the significant reliance interests implicated by the proposal and the numerous facilities and units that continue, at the Agency's insistence, working toward compliance with the 2020 rule and installation of biological treatment.

Although EPA has discretion in how it weighs the statutory factors, EPA's consideration of those factors is mandatory.[42] The statutory factors are particularly important in this rulemaking, as many affected facilities will have recently installed new technology to comply with the 2020 Rule. This fact informs the "age of equipment" factor and should weigh against EPA requiring those facilities to replace recently installed biological treatment technology with new membrane-based ZLD technology. This fact also informs the "cost of achieving effluent reductions" factor because replacing biological treatment with new membrane technology is extremely costly (when properly estimated and amortized). EPA must weigh these against the other factors in its determination that membrane-based ZLD is BAT less than three years after EPA determined that biological treatment was BAT. It is not sufficient for EPA to rely solely on pollutant reduction estimates; EPA must consider the statutory factors in its BAT decision.

At a minimum, if EPA no longer believes it is required to consider the statutory factors in its selection of BAT, or in its decision not to select a technology as BAT, it must say so, provide a rationale, and explain why it changed its position from the 2015 and 2020 Rules.

B. EPA should consider all relevant data and information.

The Southern Company has voluntarily provided significant information and data to support the regulatory development process. The most recent of which included an April 2022 submittal of FGD wastewater data

[42] *See* 33 U.S.C. § 1314(b)(2)(B) (EPA "shall take into account" the enumerated factors and any other factors that EPA deems appropriate).

for Plant Bowen. This submittal included a more detailed 2019 study and report for a 50 gallons per minute (gpm) Vibratory Shear Enhanced Processing (VSEP) membrane system at Plant Bowen. We are concerned that EPA cites only to a 2014 report, *Performance Evaluation of a Vibratory Shear Enhanced Processing Membrane System for FGD Wastewater Treatment*, conducted at the Water Research Center at Plant Bowen in 2014 as a supporting justification for their revised BAT determination. We provide the following reasons why this 2014 report on VSEP membrane performance should not be used as a basis for supporting a membrane-based BAT determination:

- The total run time of the pilot system was only 16 days and, as such, the long-term maintenance issues with this type of system, such as degradation from fouling/scaling and overall deterioration, could not be tested.
- The size of the system tested was 0.5 gpm, which is too small to identify or evaluate potential operational challenges, such as chemical usage requirements and membrane cleaning frequencies/redundancy needs.
- The operational conditions for the study period do not reflect the current reality of the wastewater matrix that will be encountered at Plant Bowen. The feedwater Total Dissolved Solids (TDS) concentration was only 12,000 to 16,000 mg/L, whereas the plant has since cycled up scrubber operations and now experiences TDS concentrations of approximately 25,000 to 35,000 mg/L.

By only citing the 2014 study and potentially omitting consideration of the 2019 study, EPA may be ignoring the most relevant and recent data and information. The 2019 study and associated reports submitted to EPA more thoroughly document that EPA has improperly evaluated the performance of these types of systems and that the overpredicted permeate recovery rates (with associated concentration management costs) are flawed. In fact, in our experience, EPA's confidence on the performance of these systems is not matched by the vendors, whom will not or are extremely hesitant to offer performance guarantees to prospective buyers.

C. EPA significantly underestimated costs of compliance associated with membrane filtration-based ZLD.

EPA must consider the costs associated with the proposed BAT, and EPA's calculated incremental costs of compliance for membranes – both capital and operation and maintenance (O&M) - are significantly underestimated. Below, we present several examples to illustrate the significant underestimation of EPA's calculated costs to comply with the new BAT for FGD wastewater:

1) Industry compliance cost estimates conducted by the Electric Power Research Institute (EPRI).
2) Site-specific cost estimates to comply at Alabama Power's Plant Miller and Georgia Power's Plant Bowen.
3) EPA's omission of costs for certain generating units that plan to operate beyond 2028.

1. EPA has significantly underestimated the total cost to the industry to implement BAT for the proposed rule.

EPA has significantly underestimated the total costs to the industry to implement the BAT for the proposed rule (Regulatory Option 3) based on chemical precipitation, membrane filtration, and brine encapsulation. EPRI's capital cost estimate is 9 times higher than EPA's capital cost estimate for the same list of 22 plants that plan to discharge FGD wastewater after 2032. Notably, EPRI's "O&M cost estimate is 43 times higher than EPA's O&M cost estimate for the same list of plants."[43] "In evaluating the total annualized costs, EPRI's estimate of the industry cost is 27 times higher than EPA's estimate."[44] "[A] significant reason for

[43] Elec. Power Research Inst. Comments on Proposed Effluent Limitations Guidelines Rule, at 33 (May 26, 2023) ("EPRI Comments").

[44] *Id.* at 33.

the O&M cost difference appears to be largely attributed to EPA's approach in underestimating brine management requirements and associated costs."[45]

A comparison of EPRI and EPA industry-wide cost estimates to convert from chemical precipitation and biological treatment to chemical precipitation, membrane filtration, and brine encapsulation is provided in Table 1 below.[46]

Table 1. Comparison of EPRI and EPA industry-wide cost estimates to convert from chemical precipitation and biological treatment to chemical precipitation, membrane filtration, and brine encapsulation.

Source of Industry Cost[1]	Capital Cost ($M)	Annual O&M Cost ($M/yr)	Total Annualized Cost ($M/yr)[2]	Ratio EPRI/EPA Capital Cost	Ratio EPRI/EPA O&M Cost	Ratio EPRI/EPA Total Annual Cost
EPRI	5,410	2,783	3,292	9	43	27
EPA	613	65	122			

$M/yr = million dollars per year (2021 dollars)

1. Includes 22 plants that are assumed to operate past 2032 and therefore required to comply with regulatory option 3 BAT: chemical precipitation, membrane filtration, with brine encapsulation. EPA cost shown in the summation of costs for 22 plants as presented in FGD Wastewater Proposed Rule Cost Database, DCN SE10416.
2. Total annualized cost which is a sum of the annualized cost of capital (assumes 7% interest rate and 20-year life) and the annual O&M cost.

EPRI's comments on the proposed rule provide a detailed analysis of how EPA has significantly underestimated BAT costs for membrane filtration for FGD wastewater treatment.[47] EPA should reevaluate its cost estimates based on EPRI's cost methodology, which is explained in detail using flow

[45] *Id*. at 35.

[46] *Id*. at 33, Table 2-1.

[47] *See id.* at 32-60.

charts and mass balance calculations. At a minimum, EPA should acknowledge the EPRI comments and correct EPA's own cost estimates or explain why it believes that EPRI's estimates are erroneous.

2. EPA significantly underestimated the cost to comply at Plants Miller and Bowen.

a. Alabama Power's Plant Miller

Alabama Power Company initiated an independent[48] pre-screening cost and feasibility study for the implementation of membrane filtration treatment based on the VIP option in the 2020 Rule, which sets BAT limits on the discharge of the permeate from a membrane filtration system with pretreatment (see Appendix A). The study included the same general scope that EPA claims to have included in its cost of compliance estimates, including purchased equipment, delivery, installation, site preparation, buildings, engineering and supervision, construction, contractor fees, operation and maintenance costs, energy usage, chemical costs, and brine sludge transport and disposal. The study did not include the total costs already spent to install the existing chemical precipitation system ($149 million) followed by biological treatment system ($122 million) currently operating at Alabama Power's Plant Miller,[49] and so the study's cost estimates can be viewed as the incremental additional costs to comply with membrane filtration. Importantly, the recent study also did not contemplate a scenario in which permeate could not be discharged,

[48] Third-party water treatment company.

[49] A comprehensive breakdown of this cost information is included in the information Southern Company Services submitted to EPA on April 1, 2022, in response to EPA's December 2021 Voluntary Request, *James H. Miller (ICR ID 01493) Phys-Chem-Bio FGD Wastewater Treatment. See* Letter from Donna Hill, Southern Company Services, Inc., *supra* note 9.

as was ultimately proposed. Failing to account for ZLD means that the cost estimates in Appendix A are artificially low.

Our site-specific evaluation for all four units at Plant Miller produced a capital cost to install membranes plus pretreatment of approximately $279 million, with an annual O&M cost of approximately $10.3 million. Again, this does not include ZLD. This is compared to EPA's estimated capital and annual O&M cost estimates for all four Miller units to fully comply with the proposed rule are $18.7 million and $0.529 million, respectively.[50] These represent significant underestimates by EPA of the incremental costs to comply with EPA's new proposed BAT that should be taken into consideration.

b. Georgia Power's Plant Bowen

For Plant Bowen, Georgia Power initiated an independent[51] pre-screening cost and feasibility study for the implementation of membrane filtration treatment based on the VIP option in the 2020 Rule, which sets BAT limits on the discharge of the permeate from a membrane filtration system (see Appendix B). The study included the same general scope that EPA claims to have included in its cost of compliance estimates, including purchased equipment, delivery, installation, site preparation, buildings, engineering and supervision, construction, contractor fees, operation and maintenance costs, energy usage, chemical costs, and brine sludge transport and disposal. The study did not include the costs already spent to install the existing chemical precipitation treatment system currently operating at Plant Bowen. The study also did

[50] In the proposed rule and supporting documents, EPA assumed under Option 3 that Plant Miller would be considered an "early adopter," thus avoiding any additional capital expenditures if it were to retire by December 31, 2032. Plant Miller only avoids costs under the proposed rule if it retires by 2032; The Southern Company has not made any commitments for Plant Miller to retire, and certainly not by 2032. EPA's costs for Plant Miller to comply with ZLD requirements are found under Option 4, which does not include an "early adopter" subcategory.

[51] Third-party water treatment company.

not evaluate or provide estimated costs for a ZLD scenario in which permeate cannot be discharged, as was ultimately proposed under the VIP option in the 2020 Rule. Not accounting for ZLD means that the cost estimates in Appendix B are artificially low.

The site-specific evaluation for Plant Bowen produced a capital cost to install membrane filtration plus pretreatment of approximately $580 million. This does not include cost for a ZLD system, which would likely include additional storage tanks, pumps, and piping to reuse the permeate/distillate as make-up water to the boiler or FGD. EPA has estimated a Plant Bowen capital cost of $90 million for membrane treatment.[52] The EPA analysis therefore represents a significant underestimation of capital compliance costs of $490 million (540%). EPA has also significantly underestimated the associated annual O&M costs ($5.3 million/year), which are not provided herein, but have been provided by EPRI in comments.[53]

EPA has assumed reduced FGD wastewater treatment costs if the system only serves two units as opposed to the currently operating four units. However, Plant Bowen FGD wastewater treatment costs do not change with a potential retirement of two units, because, when considering the water balance across the plant, the peak volume of water to be treated remains approximately the same. When units are operating, they both consume water through evaporative losses and produce wastewater. The design basis for the FGD wastewater treatment at Plant Bowen reflects a common system for all units and any potential retirements do not reduce the overall plant-wide volumes under peak conditions.

Though EPA may not be obligated to adopt the cost estimates provided in Appendix A and B, it cannot simply disregard them. Instead, EPA must consider these cost estimates, explain why the cost estimates it

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[52] Eastern Research Group, Inc., FGD Wastewater Proposed Rule Cost Database (Feb. 28, 2023) (DCN SE10416) (Doc. ID No. EPA-HQ-OW-2009-0819-9955).

[53] EPRI Comments, *supra* note 43, at 53-54.

generated are reasonable in light of competing cost estimates that are orders of magnitude higher, and consider how the range of cost estimates in the rulemaking record inform the agency's analysis of the statutory factors. Importantly, the proposed rule fails to consider the impacts of EPA's flawed economic analyses on customers.

3. EPA's cost estimates fail to include some generating units that will continue to operate beyond 2028.

In EPA's compilation of generating unit-level costs and loadings estimates by regulatory option for the 2023 proposed rule,[54] EPA assigned zero ($0) costs for FGD wastewater treatment at Plant Bowen Units 3-4 but reduced the facility's pollutant loadings to zero (0) to comply with Regulatory Option 3 (proposed rule) and Option 4, which would require ZLD for FGD wastewater. Also, EPA lists the treatment in place for Bowen Units 3-4 as "ZLD" for Options 3 and 4. By contrast, EPA's FGD Wastewater Costs Database[55] correctly assigns partial chemical precipitation as treatment in place for Bowen Units 3-4 and includes estimated costs for membrane filtration; however, it is not clear that EPA included these costs in its total industry cost for the proposed rule (as well as Option 4). In addition, EPA includes Plant Bowen on its list of plants discharging FGD wastewater beyond 2028[56] and calculates fly ash (FA) generated and availability for Plant Bowen for purposes of encapsulating the brine.[57] While Plant Bowen filed a NOPP for the PCCC

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[54] *See* Memorandum from U.S. EPA, Generating Unit-Level Costs and Loadings Estimates by Regulatory Option for the 2023 Proposed Rule – DCN SE10381 (Feb. 28, 2023) (Docket ID No. EPA-HQ-OW-2009-0819-9686).

[55] Eastern Research Group, Inc., FGD Wastewater Proposed Rule Cost Database, *supra* note 52.

[56] Memorandum from U.S. EPA, Flue Gas Desulfurization Flow Methodology for Compliance Costs and Pollutant Loadings – DCN SE10287, at 3, Table 1 (Sept. 12, 2022) (Docket ID No. EPA-HQ-OW-2009-0819-9379).

[57] *See* Memorandum from U.S. EPA, Steam Electric Supplemental Proposed Rule: Fly Ash Availability – DCN SE10242 (Feb. 27, 2023) (Docket ID No. EPA-HQ-OW-2009-0819-9685).

by 2028 subcategory under the 2020 Rule for Units 1-2,[58] Plant Bowen has not done so for Units 3-4. EPA appears to have mistakenly removed all units from the list of plants that plan to operate beyond 2028. Regarding Plant Miller, EPA has also assumed that Miller Units 1-4 will retire on December 31, 2032, because Plant Miller qualifies for the "early adopter" subcategory. However, Miller Units 1-4 have no planned retirement date. If EPA did not include Plant Bowen Units 3-4 and Plant Miller Units 1-4 costs for FGD wastewater treatment (ZLD) in its total industry costs for this rulemaking, then it should do so.

D. EPA has not adequately addressed significant non-water quality impacts associated with membrane filtration-based ZLD.

In the 2020 Rule, EPA concluded in part that membranes are not BAT because of the significant non-water quality impacts. In the proposed rule, EPA has not demonstrated that these non-water quality impacts have been resolved, but rather raises more questions about the practical viability of membrane treatment plus ZLD. As EPA knows, membranes alone are not a compliance technology but instead are a volume-reduction process that needs to be coupled with additional wastewater treatment technology, as well as processes and equipment for managing the brine concentrate. Managing these concentrate streams poses significant technical and economic challenges that EPA identified in the 2020 Rule, which are still under evaluation, and that EPA has not effectively resolved or addressed in the 2023 proposed rule.

1. Paste encapsulation eliminates beneficial use.

Less than three years ago, EPA stated in its 2020 Rule:

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[58] Southern Company, Third Quarter 2021 Earnings Conference Call, at Slide 15 (Nov. 4, 2021) (Docket ID No. EPA-HQ-OW-2009-0819-9231).

> EPA also rejects membranes as the technology basis for BAT for all existing plants because it could discourage more valuable forms of beneficial reuse of FA (such as replacing Portland cement in concrete), causing more FA to be disposed of as waste.[59]

The impact to beneficial use remains a significant problem for membrane filtration and paste encapsulation. Beneficial use of fly ash provides significant environmental and economic benefits which could be largely lost with industry-wide implementation of membrane technology. Beneficial use of fly ash results in reduction of land needed for disposal, reduction in the need to mine and process virgin materials and provides a local source of raw material for the production of durable products like concrete. Installing membrane filtration and utilizing paste encapsulation as a waste disposal method for the resulting brine, as the proposal envisions, would mean that fly ash that would otherwise have been beneficially used is instead consumed in the brine encapsulation process and landfilled, indefinitely. EPA fails to acknowledge or adequately consider these significant losses in the proposed rule.

Presently, the beneficial use market in the Company's footprint is approximately twice the amount of fly ash produced. As such, the Company currently markets approximately 95% of its generated fly ash. Removing ash availability from the local market will increase the carbon footprint resulting from the use of Portland cement and will create a lower value life cycle of infrastructure as the concrete would be less durable and would need to be replaced sooner than if it were produced with fly ash.

To further illustrate the site-specific impacts of this proposal, the membrane filtration feasibility evaluation at Alabama Power's Plant Miller concluded that the brine management solution would consume all available fly ash produced at the site, eliminating 100% of the beneficial use of fly ash at a site that currently

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[59] 85 Fed. Reg. at 64,666.

sells all available produced fly ash to the concrete industry, producing approximately $8.5M in revenue and significant avoided costs each year that flows to utility customers. Rather than providing the local economy and environment a valuable raw ingredient for concrete production, Plant Miller would instead become an on-site producer of a concrete-like waste material with no productive benefit to the community or the economy. This concrete would have to be disposed of in a landfill. EPA assumes there is available on-site permitted and constructed landfill capacity when, in fact, there is none. Plant Miller, for example, does not have an on-site landfill. Constructing a new landfill would come at a significant cost and could require acquisition of nearby properties or blasting and clearing of surrounding topography to achieve a suitable landfill location if there is available space at all.

This site-specific impact on beneficial use is not unique to Plant Miller. Georgia Power's Plant Bowen currently sells over 90% of its fly ash. While the ash sales generate approximately $5 million in associated annual revenue, this practice avoids significant handling and disposal costs for operational ash, resulting in an economic benefit to customers. In addition to the lost revenue from eliminating fly ash sales, it is expected that Plant Bowen would need to build additional landfill capacity to accommodate the new brine mixture or resort to off-site disposal at substantially increased costs.

In addition to the site-specific impacts, EPA's conclusion that the industry would retain enough available fly ash to supply the beneficial use market is not practical. There is no nationwide distribution system for fly ash beneficial use. EPA understood this in 2020 when it explained the very site-specific nature of fly ash availability to the local market, which remains valid now:

> But, while these assumptions are appropriate for nationwide cost estimates which are needed to demonstrate economic achievability for the industry as a whole, this does not necessarily mean that these assumptions should be used for analyzing the non-water quality environmental impacts associated with the resultant brine from membrane use, and in

> particular, estimating what plants are likely to do with this by-product in relation to available FA.[60]

Whether sufficient fly ash is present on site or available in the local market is a site-specific question. There is still no national depot or distribution system of fly ash to which users come for supply. Furthermore, EPA itself has recently further reinforced the idea of a limited potential future supply of available ash for beneficial use. In its recent Legacy CCR Surface Impoundments proposal[61], EPA states that "[o]lder, closed impoundments or other CCR storage areas are less likely to have CCR material of a known and reliable composition," thus limiting their potential value for future beneficial use.[62] Therefore, any assertion that CCR from storage sites could be used to fill the market supply is contradicted by EPA's recent statement regarding the future value of such CCR for beneficial use.

It is evident that EPA has not adequately addressed the significant non-water quality impact of its preferred brine management solution. Once the supply of fly ash from plants like Miller and Bowen is removed from the local market, it will not likely be replaced, and a highly valuable local resource will instead reside, as waste, in a landfill. EPA has not explained how it assessed local or site-specific impacts from the loss of fly ash for beneficial use in its non-water quality impacts analysis but should do so.

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[60] *Id.*

[61] 88 Fed. Reg. 31,982 (May 18, 2023).

[62] *Id.* at 32,029.

2. The regulatory classification of a paste encapsulation mixture under the federal CCR Rule is unclear.

Since 2019, EPA has actively advanced amendments to the CCR Rule, some of which could impact whether membrane filtration with brine encapsulation is legally, technically, or economically feasible. It is not clear whether brine encapsulation, such as paste encapsulation or ash conditioning will be considered a beneficial use of the CCR. EPA states in the 2020 Rule: "While EPA considers FA use for waste solidification and stabilization as beneficial use, the CCR waste being solidified or stabilized must still be disposed of in accordance with 40 CFR 257."[63] Beneficially used CCR should not on the one hand be exempt from federal CCR regulation by definition, and on the other, be fully subjected to requirements in 40 C.F.R. Part 257. EPA should leave regulation and disposal of fly ash to the current and any future requirements of 40 C.F.R. Part 257 and not overcomplicate long-term facility CCR compliance by upsetting established on-site ash handling practices. We encourage EPA to simply avoid these unnecessary future conflicts with the CCR Rule and reject membrane filtration as BAT for FGD wastewater.

3. Crystallization and deep well injection (DWI) technologies alternatives to paste encapsulation are not solutions for facilities that do not have enough available fly ash.

In the proposed rule, EPA evaluated alternatives "for handling the resulting brine that do not involve FA and thus would have no impact on the beneficial use of FA in other settings."[64] EPA evaluated two alternatives to paste encapsulation – deep well injection (DWI) and crystallization to a salt for disposal.

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[63] 85 Fed. Reg. at 64,666 n.50.

[64] 88 Fed. Reg. at 18,842.

EPA proposes to find that both crystallization and DWI have acceptable non-water quality environmental impacts[65] and that, while the costs are higher, they would be economically achievable.[66]

With respect to DWI, it is not available to every facility. As EPA knows, the ability to inject wastewater into a deep well is dependent upon both the site geology and the ability to permit an injection well in that facility's state. For example, Class I UIC wells (also known as DWI) are currently prohibited by regulation in the State of Alabama.[67] While there is no prohibition on Class I UIC wells in the State of Georgia, there have been none permitted to date.

EPA's other alternative, crystallization, is a high-energy evaporative process that requires heat from either the operating unit or some external source to concentrate the brine to a salt. The industry's limited experience with using this technology for FGD wastewater has been problematic. EPRI evaluated five existing ZLD wastewater treatment systems at Redhawk, Navajo, Iatan, Mayo, and Merrimack Generating Stations. The findings from these case studies and site interviews demonstrate that crystallizer systems are complex and challenging to operate. Common challenges for a crystallizer system include scaling and line plugging, system foaming, flow obstructions, salt dewatering, energy transfer impedance, and chemical and mechanical cleaning.[68]

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[65] *See* Memorandum from U.S. EPA, Methodology for Estimating Non-water Quality Environmental Impacts for the Proposed Steam Electric ELGs – DCN SE10244 (Feb. 27, 2023) (Docket ID No. EPA-HQ-OW-2009-0819-9691).

[66] *See* Memorandum from U.S. EPA, Alternative Brine Management Methodology – DCN SE10243 (Jan. 5, 2023) (Docket ID No. EPA-HQ-OW-2009-0819-9680).

[67] *See* Ala. Admin. Code r. 335-6-8-.05(1)(f).

[68] Electric Power Research Institute, Thermal Water/Wastewater Treatment Systems Chemistry Guidelines, 2020 Technical Report, 3002018776, at 7-1 (Sept. 2020).

EPA states that none of the facilities that currently generate brine as part of a ZLD system elects to encapsulate and dispose of that brine.[69] "Rather, these facilities send the concentrated brine to a crystallizer, and these resulting salt crystals can then be disposed of without the use of [fly ash]."[70] There are only a few facilities in the U.S. that have installed crystallization as a component of their FGD wastewater treatment system to generate a salt from the brine concentrate. These facilities have had significant scaling and corrosion problems with the crystallizer, and in some cases have abandoned it in favor of different treatment systems. For example, the Iatan Generating Station in Weston, Missouri initially installed two vapor compressor evaporators for treating FGD wastewater, but experienced so many operational problems since its commissioning that the facility abandoned the system and installed a Spray Dryer Evaporator (SDE) based on site-specific conditions.[71]

The other facility that has experienced significant scaling and corrosion issues with its FGD wastewater treatment system is Granite Shore's Merrimack Power Station in Bow, New Hampshire. Merrimack Station installed one brine concentrator and a two-stage multiple-effect crystallizer in 2011 to treat FGD wastewater. The system experiences significant scaling and corrosion issues even though it employs softening as a pretreatment step to remove suspended solids and scaling compounds.[72] The system, to this day, cannot operate without a small liquor purge to keep its crystallizer chemistry in balance, to manage

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[69] 88 Fed. Reg. at 18,842 n.49 ("While these systems are thermal systems rather than membrane systems, the brine generated would not differ substantially in its ultimate characteristics.").

[70] *Id*. at 18,842.

[71] Electric Power Research Institute, Thermal Water/Wastewater Treatment Systems Chemistry Guidelines, *supra* note 68, at 6-5 through 6-6.

[72] *See* Comments of Public Service Company of New Hampshire on EPA's Revised Draft of National Pollutant Discharge Elimination System Permit No. NH 0001465 for Merrimack Station (Aug. 18, 2014), *available at* https://www3.epa.gov/region1/npdes/merrimackstation/pdfs/ar/AR-1215.pdf.

the critical levels of the highly soluble salts, and to keep them within the process design envelope and avoid boiling point rise. The brine and purge have reportedly been trucked offsite to a POTW.[73] The crystallizer also reportedly does not operate most of the time due to continuous operational problems.[74]

In addition, we are not aware that EPA has cited any evidence to suggest that salts produced from crystallization will be physically and chemically stable for handling and long-term disposal. Available evidence strongly suggests that salts produced from the evaporation of FGD wastewater can be highly hygroscopic and can create a liquid upon atmospheric exposure that could potentially be included in the leachate discharge from the landfill.[75] Hygroscopic salts wreak havoc on equipment and could pose environmental and structural risk to landfills, especially if those salts migrate to the leachate collection system. In this situation, pumps and other appurtenances would need replacement to avoid corrosive failure and associated compliance risks. In the proposed rule, EPA cites one plant in China that takes its brine down to salts and then sells them for industrial use as opposed to disposal in a landfill.[76] We are unaware of any established or readily available domestic market for these salts. In sum, there are significant practical uncertainties regarding the handling and disposal of any salts produced from FGD wastewater.

Not only are crystallizers problematic from a practical standpoint, but they are also expensive and additive to the costs of membranes. Specifically, since Plant Miller sells all its operational fly ash for beneficial use

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[73] *See id.*; *see also* Region 1, Responses to Comments Public Review of Merrimack Station NPDES Permit No. NH0001465, Ch. VIII, at VIII-6, VIII-20 through VIII-22, *available at* https://www3.epa.gov/region1/npdes/merrimackstation/pdfs/final/merrimack-final-rtc-ch-8.pdf.

[74] Comments of Public Service Company of New Hampshire, *supra* note 72, at 80 n.46.

[75] *See* Electric Power Research Institute, Considerations for Concentrate Management from Wastewater Volume Reduction Technologies, 3002024773 (Jan. 2023).

[76] 88 Fed. Reg. 60 at 18,843.

in the concrete market, EPA proposes the facility could use crystallization of the brine as an alternative to paste encapsulation. EPA's cost estimates for a crystallizer at Plant Miller 1-4 are $61.5 million capital and $1.9 million annual O&M costs. For Plant Bowen, which also uses nearly all (90%) of its operational fly ash for beneficial use, EPA's cost estimates for a crystallizer are $120.3 million capital and $5.4 million annual O&M costs.[77] For Plant Bowen, the crystallizer cost would be in addition to the cost of a membrane system, which based solely on EPA's own cost estimates (which we know are low), would be a total of $210.3 million in capital costs. The same is true for Plant Miller. It is not clear whether EPA has taken these additional costs into account, since fly ash is already used for other purposes at Plants Miller and Bowen.

The significant non-water quality impacts of eliminating beneficial use of operational fly ash, coupled with the significant uncertainties of the two alternative technologies EPA identifies that would allow continued beneficial use of fly ash, supports EPA's conclusion in the 2020 Rule that membrane filtration is not BAT for FGD wastewater.

E. EPA ignores practical limitations of achieving ZLD.

EPA's proposal to set membrane treatment as BAT is further complicated by the requirement that such systems achieve ZLD. EPA arbitrarily makes this assertion by assuming that the treated permeate can simply be used for either FGD or boiler make-up without any technical challenge and at a reasonable cost. This assumption may be accurate for some facilities, but in the case of Plant Bowen and Plant Miller, there is a significant additional cost to install infrastructure to support this type of process. Significant engineering, piping, pumps, and potentially even water storage would be necessary to accomplish a closed loop system. In the case of Plant Bowen (and likely many other similar plants), it is also incorrect to assume

[77] Eastern Research Group, Inc., FGD Wastewater Proposed Rule Cost Database, *supra* note 52.

that only FGD wastewater requires treatment when units are dispatched. NPDES discharges from power plants are not limited to process wastewater but instead include industrial stormwater that is also sometimes managed through the wastewater treatment systems. This ensures that stormwater that contacts exposed materials is more thoroughly controlled prior to discharge. However, this results in water entering the wastewater treatment system even when there is no makeup water demand for treated FGD wastewater, and therefore, no operational water consumption processes to achieve ZLD. This problem is even greater at sites that have gypsum landfills/ponds for dewatering. In the case of Georgia Power's Plant Scherer, this results in the greatest FGD wastewater flow occurring when the site receives high rainfall, but all units are offline. Plant Bowen has mechanical gypsum dewatering, but also has the same challenges with the FGD water balance. A comprehensive evaluation of the water balances necessary to achieve ZLD has yet to occur, but it is possible that generating units may need to dispatch solely for purposes of water consumption to achieve the ZLD requirement in this proposal. In fact, Mississippi Power's Plant Daniel has had to dispatch units due to a build-up of water in the pond at the gypsum storage facility due to heavy rains and low dispatch of the units.

IV. COMPLIANCE TIMING AND SUBCATEGORIES

The Southern Company supports regulations that facilitate the continued delivery of clean, safe, reliable and affordable energy to customers. The Company's planning process provides customers with reliable and affordable electric service from a diverse portfolio of demand-side and supply-side resources. This portfolio – comprised of demand response, energy efficiency, nuclear, natural gas, oil, coal, hydro, solar, wind, landfill gas, and biomass generation – maximizes value for customers in a wide variety of future economic and regulatory scenarios.

The Company considers retirement options for generating units as a part of the overall resource strategy. If environmental controls are mandated for a unit, then the economic value of the unit, including future operating costs, changes. The Company must then consider through thorough economic and planning evaluations whether it is in the best interest of customers to install the required control technology or to retire the unit and replace it with another resource. Accordingly, any compliance deadlines set by the proposed Supplemental ELG rule and other environmental rulemakings must consider the costs associated with any new rulemaking as well as the process and timing requirements of state regulatory processes, especially the integrated resource planning processes for the retail electric operating companies governed by the state PSCs.

As proposed, the FGD wastewater treatment requirements, compliance applicability date, and "early adopter" subcategory pose significant challenges to the Company's traditional electric operating companies. As explained in more detail below, we urge EPA to create additional flexibilities to alleviate the disparate costs associated with procuring and optimizing new biological treatment technology by 2025, and then immediately procuring and optimizing new membrane treatment technology and prematurely retiring the new biological system by 2029. We also urge EPA to evaluate any subcategories finalized under this rule with the subcategories in the CAA Section 111 rulemakings addressing GHG emissions from new and existing sources.

In this section, we present the following proposals in more detail for EPA's consideration:

- EPA should modify the FGD wastewater "no later than" applicability date to avoid disparate costs and avoid premature retirement of new treatment equipment.
- EPA should retain the existing PCCC by 2028 subcategory and create a new PCCC by 2035 subcategory.
- EPA should make modifications to the early adopter subcategory; and

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- EPA should align compliance timing and subcategory options with other impactful proposed environmental rules.

A. EPA should modify the FGD wastewater "no later than" applicability date to avoid disparate costs and avoid premature retirement of new treatment equipment.

Should EPA finalize membrane filtration based ZLD as BAT, then EPA should extend the "no later than" applicability date for all facilities until December 31, 2032. EPA should allow operation of the 2020 BAT for at least eight years to allow cost recovery for investments in 2020 Rule compliance, after which a facility can opt to either retire, repower, or continue operating with the new BAT. Reducing the useful life of a new biological treatment system to only four years places an acute cost recovery burden on customers and is a waste of resources. Modifying the "no later than" applicability date would allow continued operation of units that are, or may become, necessary for reliability due to load growth or other market changes; and it would allow facilities to evaluate the impacts of a multitude of relevant factors, including additional environmental rulemakings, affecting their continued operation and continue to operate by implementing the new BAT if they determine it to be the most cost-effective option. Therefore, EPA should extend the "no later than" applicability date for all facilities until December 31, 2032.

B. EPA should retain the existing PCCC by 2028 subcategory and create a new PCCC by 2035 subcategory.

1. EPA should retain existing PCCC by 2028 subcategory, as finalized in 2020.

EPA solicits comment on the proposal to retain the PCCC by 2028 subcategory. We agree that the existing PCCC by 2028 subcategory continues to be warranted and we urge EPA to not retroactively impose any

new requirements on facilities that have opted into this subcategory. The Southern Company's traditional electric operating companies submitted NOPPs for a combined total of 12 units stating their intent to retire or repower using alternative fuel by December 31, 2028. Of these 12, 10 units have received regulatory approval to retire or repower by 2028. Georgia Power requested to retire Plant Bowen Units 1&2 by 2028; however, in consideration of the reliability needs of customers in North Georgia, the Georgia PSC deferred a decision on the retirement of Plant Bowen Units 1&2 until the Georgia Power's next regularly scheduled Integrated Resource Plan (IRP) in 2025. EPA also requests comment on whether a more stringent technology already existing on site should be required for FGD wastewater at facilities in the PCCC subcategory. The imposition of any additional requirements to these facilities only adds corresponding disparate costs. Additionally, because some existing treatment systems may be utilized for treatment of ash pond dewatering activities, it is imperative that EPA not impose any complications or delays to the timely dewatering and closure of ash ponds, which are already under prescriptive closure deadlines under 40 C.F.R. § 257.102(f), with extremely limited extension options. We suggest that avoiding this unintended consequence would best support EPA's stated goal of harmonization with the CCR Rule.

2. EPA should establish a new PCCC subcategory allowing units the option to comply with the generally applicable limitations by the "no later than" applicability date in the facility's permit or retire or repower by December 31, 2035.

EPA should finalize a new subcategory that would allow facilities the option to comply with the 2020 BAT no later than December 31, 2025, and, by a certain date, opt to either comply with the new membrane filtration BAT for FGD wastewater no later than the finalized applicability date or opt to retire or repower no later than December 31, 2035. In the proposed rule, EPA reaffirms its support for the PCCC by 2028 subcategory: "EPA established this subcategory in the 2020 rule based on the statutory factors of cost (the

cost burden on these facilities is greater because they have less time to recoup investments); the age of the equipment and plants involved (the remaining useful life of the plants and their pollutant control equipment is shorter than for typical plants); potential non-water quality environmental impacts, including energy requirements (early retirement of these plants could affect energy supply); and harmonization with the CCR Rule alternative closure provisions."[78] This subcategory approach is supported largely by the same factors EPA relied upon for the PCCC by 2028 subcategory and is necessary for the same reasons outlined in our discussion regarding modifications to the early adopter subcategory.

In the following sections, we present additional factors for EPA to consider in finalizing a new PCCC subcategory that most appropriately addresses the timing associated with the planning, regulatory approval and implementation of any necessary replacement generation for generation units impacted by this proposed rulemaking. Based on factors presented below, we urge EPA to establish a new PCCC subcategory allowing retirement or repowering by December 31, 2035.

a. A retirement subcategory should appropriately consider the planning and regulatory approval process.

As an illustration of the critical timing considerations of state regulatory processes, Georgia Power is required to complete extensive planning analyses as a vertically integrated utility regulated by the PSC under O.C.G.A. § 46-2-20(a). The PSC oversees and must approve of planning and resource decisions to ensure Georgia Power can meet its obligation to serve its customers, including ensuring the Company maintains sufficient capacity to serve during periods of peak energy demands. Georgia Power is required under PSC regulations to act prudently in its investment and compliance decisions. Those decisions are

[78] 88 Fed. Reg. at 18,857; *see also* 40 C.F.R. §§ 257.71(d), 257.103.

reviewed as part of statutorily required, triennial IRP proceedings, subject to Commission review and approval, which comprehensively evaluate Georgia Power's plans for the next 20 years. The IRP process allows interested members of the public the right to participate in multiple ways, including engaging in the thorough review of the Company's plans by intervening in the case or providing comments during a public hearing.

Decisions on how best to meet the needs of customers are not relegated to a singular analysis. Georgia law acknowledges this by requiring a planning process that is truly integrated and recognizes the supply-side dynamics of forecasted needs, transmission, environmental compliance, and generation. The development of the IRP is a complex process requiring coordination from across the Company that takes significant time to complete. As a part of the three-year planning cycle, planning for and preparing the IRP takes a year or more, the IRP and any associated rate case proceedings take another year, and implementation of the Commission decisions is the focus of the following year and beyond. Through the IRP process, the Company ultimately submits to the Commission its long-term plan to meet the needs of customers by providing reliable, cost-effective electricity while also complying with a range of environmental laws.

Given this regulatory framework, Georgia Power must carefully evaluate the implications for operations, reliability, and the impacts on customers through the IRP process while considering environmental compliance strategy decisions to control or retire and replace generating resources. By way of example, Georgia Power is procedurally required to submit to its PSC an IRP at least every three years that details its long-term plans for its energy resources to meet customer energy demands. To modify its generation portfolio, Georgia Power must follow Commission rules and, for large resources, would be required to issue a request for proposals (RFPs), evaluate RFP bids, and apply for certification of the new resource(s) with the PSC. To receive approval of a certification request, the utility must ensure prudency of the RFP process, which necessitates a thorough and equitable evaluation. Georgia Power typically requires between 19 and

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30 months before resources are certified or activities associated with building a new resource are initiated. Up to six months of additional time may also be required prior to the certification filing depending on the level of activity at the Commission and whether certification requests will be included as part of an upcoming triennial IRP filing. Of special note is the fact that the state law prohibits an electric utility from commencing construction until a certificate is obtained from the PSC. With the robust regulatory process that is required by law, any decision to retire a generating unit necessarily follows a multi-year evaluation to ensure that customers' best interests are fully considered. EPA must consider these state regulatory process requirements in setting any guidelines around timelines for unit retirement commitments.

b. A retirement subcategory should appropriately consider the timing required for replacement generation and transmission.

In the Southern Company's January 2020 comments to EPA[79], Southern provided support for a timeframe of *at least* 8 years for a utility to obtain necessary regulatory approvals to retire coal units and complete the construction of new generation. This timeline was largely based on a historical example illustrating the approval and construction of three new gas-fired units at Georgia Power's Plant McDonough. In these comments, we also noted the following key issues that may also affect the actual timing that may be required to replace generation: 1) transmission constraints are an important and critical component for new or retiring generation, and that significant transmission upgrades may be needed to support reliable operations and resiliency of the system, depending on the location of the generation; and 2) these updates may require long lead-time planning, land acquisition, design, and construction efforts in order to support the new generation or accommodate future retirements.

[79] Comment Letter from Jeffrey A. Burleson, Senior Vice President, Environmental and System Planning, Southern Company, *supra* note 38, at 49-53.

In the case of Georgia Power, because this rulemaking more specifically impacts the potential economic viability of Georgia Power's Plant Bowen, more current and site-specific impacts must be considered. Plant Bowen presents a different scenario than Plant McDonough in that the existing generating capacity of Plant Bowen represents the largest single facility that will have been retired to date. Due to its location and size, to replace the generation capacity of Plant Bowen, both very significant new transmission development and generation replacement are required. Georgia Power currently anticipates that the necessary transmission projects and additional generation to replace Plant Bowen while maintaining reliability could require timelines through the end of 2035, including completion of the robust regulatory approval process and associated RFP and certification process. While certain extensive transmission projects are already underway to allow for the eventual retirement of Plant Bowen, the acceleration of the timeline required to meet the 2029 compliance deadline is not possible. With numerous individual transmission projects required, planning for the timing of construction and outages is critical to maintain reliability for customers throughout the process. Even if critical factors such as supply chain, labor and transmission and generation outage planning needs are ignored, the acceleration of the timeline would require even more extensive transmission work than currently planned, almost doubling the cost (from about half a billion dollars to about one billion dollars). And yet, doubling the cost still does not make the timeline achievable when all factors are appropriately considered. Until the completion of this transmission work, Plant Bowen remains critical to maintaining electric service reliability in Georgia.

Further, procuring and/or building replacement generation to prepare for the eventual retirement of over 3,000 megawatts of capacity at Plant Bowen has critical timing considerations. Currently, Georgia Power is in the process of deploying generation capacity through power purchase agreements (PPAs) of about 2,300 megawatts to prepare for currently approved plant retirements (which does not include Plant Bowen) through 2028. Planning for the 2019 IRP, which included the proposed RFP process, began before 2018, the proposed RFP process was approved by the Commission in the 2019 IRP, selected resources from the

RFP process were approved during the 2022 IRP, and the resources are anticipated to begin serving customers between 2024 and 2028. Thus, full deployment of these resources, which are all existing resources with no new construction required, will take at least 10 years from start to finish. Meanwhile, additional coal plant retirements beyond those already approved through 2028 will only increase the complexities of market supply and demand for electricity and are expected to further challenge and prolong these timeframes.

Taking all of these relevant factors into consideration, the end of 2035 is the earliest feasible and responsible date to consider for the retirement of Plant Bowen in order to maintain reliability and resiliency of the electric grid in north Georgia and affordability for customers. If EPA finalizes the proposed BAT, EPA should finalize a new subcategory that allows plants such as Plant Bowen the time necessary to construct replacement generation and transmission necessary to accommodate its retirement without the addition of disparate costs to customers that would be imposed by the proposed new BAT for FGD wastewater. This new subcategory must consider the multi-year planning and evaluation process before unit retirements can be approved, as well as the complex planning and coordination necessary prior to construction of transmission and replacement generation for coal plants that are expected to remain after 2028. In the case of Plant Bowen, this subcategory should allow the plant to continue operating the 2020 BAT, and by a certain date no earlier than December 31, 2028, to align with the constructive state regulatory processes required by law, commit to either install the newly required BAT by December 31, 2032, or commit to retire or repower by December 31, 2035. This option mirrors the successful PCCC by 2028 subcategory and ensures resource decisions can be made in the best interest of customers.

C. EPA should make modifications to the early adopter subcategory.

EPA has proposed a new subcategory for plants that have achieved compliance either with the 2015 or 2020 rule limitations on FGD wastewater and BA transport water by the publication of this proposed rule, and

which elect to retire no later than December 31, 2032. As a condition of being eligible for this subcategory, EPA proposes that permitting authorities include the BAT limitations in these sources' permits after December 31, 2032. EPA reasons that such a subcategory is warranted on the basis of cost (disparate costs to facilities with these units), age (both the age of the new pollution treatment technology and the remaining useful life of the plant), non-water quality environmental impacts (air pollution), and other factors the Administrator deems appropriate (impacts to early adopters who relied on the identification of biological treatment as BAT for FGD wastewater in the 2015 and 2020 Rules). EPA also reasons that utilities that have "avoided incurring any cost for as long as possible" may be better poised to adjust to this proposed rule.

As proposed, the "early adopter" subcategory inadequately assesses the entirety of effort and investments made toward compliance with the 2015 and 2020 rules across the industry, as well as the projected retirement horizons of those assumed to be "early adopters;" and therefore produces an unfair and unequitable outcome for both those that are included as early adopters but have no plans to retire by 2032 as well as those who are excluded from the subcategory even though they may have already converted to dry ash handling systems and/or made substantial and irreversible financial commitments to comply with the 2020 BAT for BATW and FGD wastewater (which could also include the early operation of a physical chemical treatment system).

In our comments, we have presented site-specific cost estimates for Plants Miller and Bowen, illustrating that the projected costs to comply with the newly proposed BAT are far greater than EPA has estimated. Further, EPA's limited review of projected retirement horizons has likely excluded retirement commitments that extend beyond the December 31, 2032, date, by only a few years. Expanding this review to include units that may retire by the end of 2035 would both alleviate disparate costs to a wider population of aging units and weigh in favor of EPA's consideration of non-water quality environmental impacts, such as

reduced air emissions. Finally, the other factors EPA relies upon (impacts to early adopters who relied on the identification of biological treatment as BAT for FGD wastewater in the 2015 and 2020 Rules) unfairly penalizes facilities that also fully complied with the law and made decisions in the best interests of customers.

Accordingly, we present solutions for EPA to consider in finalizing the early adopter subcategory to produce fair and equitable outcomes while maximizing the environmental benefits of complying with the 2015, 2020 and this Supplemental ELG rulemaking.

1. EPA should revise the "cut-off" date or qualification date to include facilities that have entered into a contract with a vendor to install technologies to comply with the 2020 Rule BAT.

EPA's proposed eligibility "cut-off" date or qualification date for this subcategory should be changed. EPA requested comments on this issue. EPA's proposed March 29, 2023, qualification date creates fair notice and equitable concerns. EPA never previously identified the March 29, 2023, date as one from which regulatory consequences would flow. The first notice anyone may have had of this date and its significance was disclosed in the pre-publication version of the proposed rule, released by EPA on March 8, 2023. However, that pre-publication version was also internally inconsistent, referring to the Federal Register date of the proposed rule in certain instances, while referring to a date after publication of the final ELG rule in other instances. Accordingly, the industry had no opportunity to conform its conduct to this new legal standard. Many facilities are currently in the process of contracting for and constructing a biological treatment system to comply with the 2020 Rule. The only fair and just approach would be to extend the eligibility date to one that's after the effective date of a final rule. Only then will a party considering whether to opt-in to this subcategory have the ability to conform its conduct and also have full knowledge of its legal obligations and options to make a fully informed compliance decision.

2. The early adopter subcategory eligibility should not be limited to only those that have completed installation and demonstrated compliance with the 2020 Rule requirements.

The early adopter subcategory eligibility should not be limited to only those that have completed installation and demonstrated compliance with the 2020 Rule requirements. It is enough that companies and facilities have made sizeable (and sometimes irreversible) commitments to install a treatment system to comply with the 2020 Rule. EPA has recognized in 2015, 2020, and in this proposed rule that the installation of these complex treatment systems is a multi-year process. Despite this, the Agency is proposing to establish an eligibility criterion that ignores the fact that many companies and facilities may have spent millions of dollars to achieve compliance with the 2020 Rule but may be one or two years away from achieving compliance; while other facilities may have executed a contract with a vendor for the installation of a 2020 ELG rule-compliant treatment system but may not be able to meaningfully amend or void that contract.

For example, the proposed qualification date for the early adopter subcategory will prevent Plant Bowen from qualifying for the subcategory. Plant Bowen has entered a contract with a vendor for the installation of a biological treatment system and has already incurred more than $50 million to pursue, plan, finance, and design how it will comply with the 2020 Rule, because its NPDES permit requires the new biological treatment system to be in service to meet the 2020 Rule limits by December 31, 2025. Depending on when a final rule is issued, Plant Bowen's current compliance costs will likely increase another $30-40 million.

A reasonable and workable subcategory needs to provide relief to permittees that initiated actions to comply with the 2020 Rule. Stated simply, the early adopter subcategory needs to provide relief not only for those facilities that have completed the installation and optimization process to achieve compliance, but also for those that have taken meaningful steps toward complying with 2020 Rule. To address these concerns, the only fair and just approach would be to revise the eligibility criteria and include units that have already

contracted for but not yet installed biological treatment to comply with the 2020 Rule, *i.e.*, entered into a contract by the signature date of the final rule.

3. EPA should not require retirement for early adopters.

As mentioned previously, the proposed early adopter subcategory unfairly treats even those that would qualify by requiring retirement. This requirement is largely unexplained by EPA (which makes it arbitrary and capricious) and misses the point on why the "early adopter" subcategory is necessary and equitable. The subcategory is warranted because: (1) of the reliance interests of early adopters (as explained herein); (2) these units should not be forced to abandon these new treatment technologies after only a few years (when their useful life is well-established as 20+ years); and (3) customers should not be immediately subjected to additional (or even overlapping) rate increases because of EPA's changing regulatory positions. EPA's proposal also fails to adequately take into consideration the environmental benefits already experienced at such facilities by installing and operating the 2020 BAT earlier than December 31, 2025 (Plant Miller), installing and operating a physical chemical treatment system as progress toward compliance with the 2020 BAT (Plant Bowen), and/or converting to dry bottom ash handling systems well in advance of this proposed rulemaking (Plants Miller and Bowen). Requiring retirement to qualify for this subcategory seems punitive. As opposed to penalizing these facilities with an early retirement option that is neither feasible nor coordinated with simultaneously proposed environmental rulemakings, EPA should simply remove the requirement for early adopters to commit to retirement and should instead allow early adopters to either retire or continue operating under the new BAT no later than December 31, 2032.

4. If EPA's early adopter subcategory requires a retirement commitment, then EPA should allow early adopters to either comply with new generally applicable limits by December 31, 2032, or commit to retire by December 31, 2035.

While we believe EPA should not require retirement for early adopters, if EPA ultimately decides to finalize an early adopter subcategory that requires a retirement commitment, then EPA should: 1) as discussed above, require compliance with the new generally applicable limits no later than December 31, 2032, and 2) extend the retirement date from December 31, 2032 to December 31, 2035. As discussed previously, EPA's review of facilities that may soon retire fell short of including a potentially substantial number of units that may elect to retire no later than the end of 2035, including Plant Bowen. EPA cited retirement plans made by utilities beyond December 31, 2032, but, without full explanation, excluded these units as early adopters by establishing a retirement date that is not achievable. In doing so, EPA has set up a potential outcome that not only fails to capture the full scope of non-water quality benefits that could be associated with an expanded subcategory (e.g., reduced air emissions), but also results in an untenable situation for units that: 1) should qualify as early adopters based on progress toward 2015 and 2020 Rule compliance, and 2) would experience disparate costs and potential reliability concerns due to the age of the units and associated timelines for completing necessary generation replacement and transmission infrastructure upgrades. In our preceding sections, we presented a scenario for Georgia Power's Plant Bowen that strongly supports both the need for such a retirement subcategory and an associated date to retire by December 31, 2035. We recommend that the timing of a retirement commitment under the early adopter subcategory should mirror that which we have recommended for a new PCCC by 2035 subcategory.

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D. EPA should align compliance timing and subcategory options with other impactful proposed environmental rules.

As a general matter, whether through establishment of an early adopter subcategory or with stand-alone subcategories that allow flexibilities in compliance timing and associated requirements, EPA should take steps to ensure harmonization with other impactful environmental rules, including, but not limited to, CAA Section 111 rulemakings. Given the substantially underestimated costs of the proposed new BAT in this rulemaking and the proposed expedited timeframe to achieve compliance, utilities should have the appropriate time to evaluate the impact of multiple rulemakings on the generation fleet and make decisions that are protective of the environment and in the best interests of customers. Extending the time to comply with any new proposed BAT until at least December 31, 2032, and extending the date by which units must commit to retire to December 31, 2035, under any new retirement subcategory best achieves this outcome.

V. LEGACY WASTEWATER (LWW)

In spring of 2016, The Southern Company announced that operating companies would stop sending coal ash to unlined ponds by spring of 2019, except for one facility. By spring of 2019, the Company's operating companies fulfilled this commitment through an aggressive ash and wastewater management program. By the end of 2020, all the Company's operating companies had completely discontinued sending both CCR and non-CCR waste streams to our ash ponds – ahead of EPA's April 11, 2021, deadline. Twenty-one units across six sites (Plants Barry, Bowen, Gaston, Miller, Scherer, and Wansley) converted to dry/closed loop ash handling (even as early as August 2018) and the water treatment functionality of the ash ponds was replaced at 12 sites, comprising a $2.6 billion program.

EPA has proposed several changes to LWW requirements in the proposal, including subdividing LWW into new categories, new definitions, and requiring different management requirements for the new

categories. As a general matter, Southern urges caution with any revision to the LWW requirements that could complicate, delay, or derail ongoing dewatering and closure activities required by the CCR Rule.

A. EPA should not subdivide LWW.

EPA is proposing in this rule to segregate LWW into two main categories of separately regulated discharges, which would each be subject to separate case-by-case technology-based effluent limitations established by the permitting authority. These two main categories are described as follows:

1) Wastewater continuously or intermittently generated and discharged to a pond after the issuance of the first permit implementing the 2015 or 2020 Rule but before the compliance date specified in the permit (the "as soon as possible" date required by the rule), and

2) Wastewater that was discharged to the pond previously and will be discharged when the pond is dewatered for closure.

The Southern Company believes these proposed definitional changes to be unnecessary. While there is value in acknowledging the current status of waste streams in the context of how the CCR and ELG Rules have impacted the on-site management and treatment of these waste streams, as proposed, EPA's subdivision of LWW is problematic. The proposed subdivision allows for a scenario where a wastewater may have been sent to the pond after permit issuance but before its late applicability date in the permit. The definition becomes retroactive in a manner that is impossible to achieve. If a facility were to discharge wastewater continuously or intermittently to a pond after the issuance of a permit, then this wastewater would not be separable, physically, or otherwise, from wastewater that was discharged to that same pond prior to the issuance of the permit. In this scenario, there is no significant difference in composition between the two categories of LWW. The only difference is when the LWW was generated. If separated by time, both categories of LWW with similar composition will be treated to meet the existing ELGs and any water

quality-based effluent limits in the NPDES permit prior to discharge. Therefore, EPA does not need to propose separate subcategories of LWW separated by time or propose that the permit writer conduct a separate ELG BAT determination on each category to set BPJ limits. This is unnecessary, creates confusion, and adds an extra burden to the permit writer.

B. If EPA chooses to subdivide LWW, then EPA should do so based on the following temporal marker: the later date of either when a pond stopped receiving these waste streams (i.e., the "cease receipt" date of CCR and non-CCR wastes for unlined ponds) or the issuance of the first permit implementing the 2015 or 2020 Rule.

If EPA does subdivide LWW into different categories, then EPA could instead consider establishing a more practical temporal marker to subdivide these waste streams: the later date of either when the pond stopped receiving these waste streams (i.e., the "cease receipt" date of CCR and non-CCR wastes for unlined ponds) or the issuance of the first permit implementing the 2015 or 2020 Rule either renewal or modification. In this scenario, there would be no instance where the subdivided wastewater would have already been sent to the pond, and a facility that stopped sending wastewater to ponds earlier than the issuance of the NPDES permit would not be subject to these requirements any earlier than the date of issuance of the first permit implementing the 2015 or 2020 Rule.

Even if EPA can establish a practical subdivision, there may be little practical effect for any LWW other than FGD wastewater, as it is likely that facilities would have implemented the 2015 BAT for fly ash transport water (FATW) prior to, or at latest, concurrent with, the date that they stopped sending LWW to the pond. Presuming EPA issues a final rule in 2024, many facilities would be well underway toward installation and testing of the 2020 BAT to meet the applicability date established in the permit, no later

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than December 31, 2025. At Plants Bowen and Miller, both FATW and BATW are already meeting the 2020 BAT, and FGD wastewater is being treated by either chemical precipitation (Plant Bowen) or the 2020 BAT (Plant Miller). Even in the case where FGD wastewater were re-rerouted from an unlined CCR impoundment to a lined settling pond, the effluent would still be discharged through an NPDES permitted outfall and subject to meeting existing ELGs and state water quality standards. Therefore, there is no reason to separate this waste stream as a subdivision of LWW for purposes of this rulemaking since EPA's objective of achieving a more effective treatment for FGD wastewater until the 2020 BAT applicability date is likely already occurring in many cases.

C. EPA should not subcategorize LWW that was discharged to the pond previously and will be discharged when the pond is dewatered for closure.

EPA is proposing to further subcategorize the second major proposed category of LWW: that which was discharged to the pond previously and will be discharged when the pond is dewatered for closure. This is effectively the wastewater that remains in the pond after the pond has ceased receipt of both CCR and non-CCR wastes. This wastewater may exist above the settled CCR solids within the pond or as interstitial water surrounding the settled CCR solids. EPA's proposed subdivision of this category is as follows:

- Surface impoundment (SI) decant wastewater: surficial water located above the CCR solids (hereafter referred to as ''surface impoundment (SI) decant wastewater''), or the layer of a closing surface impoundment's wastewater that is located from the water surface down to the level sufficiently above any coal combustion residuals that, when drained, does not resuspend the coal combustion residuals; and

- Surface impoundment (SI) dewatering wastewater: Pore water in the saturated CCR layer at levels beyond that needed for conditioning, or the layer of a closing surface impoundment's wastewater

> that is located below surface impoundment decant water due to its contact with either stationary or resuspended coal combustion residuals.

Since the beginning of dewatering efforts, our facilities have recognized and addressed the potential differences in pollutant levels associated with progressive dewatering. This is evident from the dewatering data the Company voluntarily provided to EPA in April 2022. In practice, a single technology can be used to treat both types of surface impoundment wastewaters with modifications to the treatment process (*e.g.*, addition of chemicals to remove pollutants) to protect receiving stream water quality. Therefore, we suggest that this specific subcategorization is unnecessary and irrelevant for purposes of establishing effluent limits for dewatering wastewater. If there is water removed from an impoundment during closure through dewatering, then it should be referred to collectively as "dewatering wastewater."

Importantly, EPA's definition of this LWW refers to wastewater within an impoundment that is in the process of being closed (i.e., "a closing surface impoundment"). We support EPA's decision to limit this definition to wastewater that is removed from within the impoundment to facilitate closure. We question, however the intent of EPA's description of surface impoundment dewatering wastewater in the preamble as that which is present "in the saturated CCR at levels beyond that needed for conditioning." For purposes of this ELG rulemaking, knowing whether a wastewater is present "at levels beyond that needed for conditioning" serves no purpose.

As stated above, EPA should not further subcategorize LWW that was discharged to the pond previously and will be discharged when the pond is dewatered for closure. Our experience and information/data provided to EPA has shown that this subcategorization is not necessary.[80] However, should EPA ultimately

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[80] Letter from Donna Hill, Southern Company Services, Inc., *supra* note 9.

choose to define these two subcategories, then EPA should remove any reference regarding the degree to which the wastewater is present "in the saturated CCR at levels beyond that needed for conditioning."

D. EPA should not establish more stringent LWW treatment requirements that hinder pond closure.

As described above, the Company's operating companies have moved aggressively to replace surface impoundments as wastewater treatment units, rerouting LWWs to robust treatment systems that protects receiving water quality and facilitates pond closure activities. EPA is correct in its stated uncertainty as to whether more stringent systems (chemical precipitation, biological treatment, membrane filtration, thermal evaporation, spray dryer evaporation) could be used nationwide "without disrupting some plants' already commenced (and contracted for) closure process, thereby possibly jeopardizing the ability of those plants to meet their closure deadlines under the CCR Rule."[81] We agree that EPA should avoid establishing requirements (either through more stringent technologies or through permitting constraints) that would interfere with the closure progress or become a linchpin of the pond closure schedule. To account for this, EPA could specifically instruct permit writers to take into consideration in their BPJ analyses a facility's current dewatering treatment system, dewatering status, and CCR closure timeline, and establish effluent limitations accordingly. It is imperative that, given the already stringent deadlines for completing closure, these activities proceed expeditiously and without delays associated with the imposition of an unnecessarily stringent technology, even if it is perceived as readily available at the site.

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[81] 88 Fed. Reg. at 18,853.

VI. COMBUSTION RESIDUAL LEACHATE (CRL)

EPA has maintained the definition for CRL from the original 2015 rulemaking, which defines CRL as "liquid, including any suspended or dissolved constituents in the liquid, which has percolated through or drained from waste or other materials placed in a landfill, or that passes through the containment structure (e.g., bottom, dikes, berms) of a surface impoundment."[82] EPA is proposing chemical precipitation as the technology basis for establishing BAT limitations to control pollutants discharged in CRL. EPA proposes that this technology is available, is economically achievable, and has acceptable non-water quality environmental impacts. Specifically, the proposed BAT basis consists of chemical precipitation/coprecipitation employing the combination of hydroxide precipitation, iron coprecipitation, and sulfide precipitation. The Company does not object to the proposed BAT limits for arsenic and mercury for this waste stream but believes EPA should constrain the scope of regulated CRL to that which is collected from engineered leachate collection systems and then discharged via surface outfalls from active landfills at active generating plants. Subjecting numerous unidentified and uncharacterized sources of water to an improper regulatory definition completely unbalances any underlying determinations or assumptions of cost-effectiveness. In particular, this rulemaking should not establish effluent limits or permitting requirements for functional equivalent discharges of CRL because unlined landfills and surface impoundments are not point sources.

[82] 80 Fed. Reg. 67,838, 67,847 (Nov. 3, 2015).

A. EPA's proposed BAT limits for functional equivalent discharges of CRL represents a regulatory overreach and should not be finalized.

As part of the proposal, EPA has included new guidance to implement the U.S. Supreme Court's decision in *County of Maui*.[83] The proposed guidance is presented as having limited applicability, but it actually represents a significant regulatory overreach. Notably, in 2020, EPA published for comment a proposed standalone guidance document that would help inform how to broadly incorporate *County of Maui* into existing NPDES permit programs. EPA finalized that guidance in January 2021, only to rescind it several months later. Now, years later, EPA proposes new *County of Maui* guidance but has tucked it into a larger, industry-specific rulemaking. As described below, the substance of EPA's proposed *County of Maui* guidance is flawed, as is the Agency's decision to propose it, for the first time, as part of this industry specific ELG rulemaking.

1. Unlined landfills and surface impoundments are not point sources.

In *County of Maui*, the existence of a "point source" was both a necessary predicate and *undisputed* (there, wastewater was injected directly into groundwater through an engineered underground injection control system). However, unlined landfills and surface impoundments are *not* point sources. In the only cases directly on point, both the Fourth Circuit and Sixth Circuit Court of Appeals rejected all arguments to the contrary.

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[83] *Cty. of Maui v. Haw. Wildlife Fund*, 140 S. Ct. 1462 (2020).

In the Fourth Circuit case, *Sierra Club v. Virginia Electric & Power Company*,[84] Sierra Club argued that seepage of CRL from an unlined landfill and settling ponds at the Chesapeake Energy Center in Virginia constituted unpermitted point source discharges under the CWA. But the court disagreed, ruling that they did not function as conveyances and thus did not meet the statutory definition of point source. The court went on to explain that in regulating discharges of pollutants from point sources, Congress clearly intended to target the measurable discharge of pollutants.

> When a source works affirmatively to *convey* a pollutant, the concentration of the pollutant and the rate at which it is discharged by that conveyance *can be measured*. But when the alleged discharge is diffuse and not the product of a discrete conveyance, that task is virtually impossible.[85]

The court concluded that the scenario presented by the unlined landfill and settling ponds at Chesapeake Energy Center "indicates circumstances that are incompatible with the effluent limitation scheme that lies at the heart of the Clean Water Act."[86]

In *Ky. Waterways Alliance. v. Kentucky Utilities Company*, the Sixth Circuit reached the identical conclusion in a case involving two coal ash ponds at the E.W. Brown Generating Station in Kentucky.

> Here [plaintiffs] contend that the coal ash ponds are point sources. We doubt the correctness of that position. A point source, by definition, is a "conveyance." 33 U.S.C. § 1362(14). Coal ash ponds are not conveyances – they do not "take or carry [pollutants] from one place to another." . . . In fact, ash ponds are quite the opposite; they are designed to *store* coal ash in place.[87]

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[84] 903 F.3d 403 (4th Cir. 2018).

[85] *Id*. at 411 (emphasis in original).

[86] *Id*.

[87] 905 F.3d 925, 934 n.8 (6th Cir. 2018), *abrogated by Cty. of Maui, Hawaii v. Hawaii Wildlife Fund*, 140 S. Ct. 1462 (2020) (internal citations omitted) (emphasis in original).

EPA fails to reconcile or even acknowledge the existence of these controlling cases in its proposal. Instead, EPA purports to dodge the point source requirement altogether: "EPA, through this action, is not addressing the definition of any terms in the CWA (such as 'point source' or 'discharge of a pollutant') that governs when a discharge is subject to NPDES permitting requirements . . . ."[88] EPA's position is untenable and any attempt to regulate CRL through groundwater from unlined landfills and surface impoundments must be rejected.

2. EPA has not yet taken the steps necessary to implement *County of Maui*.

Even assuming, for the sake of argument, that a point source exists, EPA's proposal would still be inappropriate. In the three years since the Supreme Court issued *County of Maui*, EPA has not yet taken the required regulatory steps necessary to bring functional equivalent discharges into the NPDES permit program. First, EPA has not amended the NPDES regulations at 40 C.F.R. Part 122 to implement *County of Maui*, either in terms of the scope of the NPDES permit requirements in § 122.1(b) or the application requirements in § 122.21 *et seq*. Second, EPA has not revised the required application forms to encompass the types of data and information needed to determine the existence of, and develop the limitations and conditions applicable to, functional equivalent discharges. Indeed, across EPA's complete set of forms and instructions for the entire universe of regulated NPDES discharges, there is not a single reference to functional equivalent discharges.[89] Third, EPA has not issued any guidance that interprets or applies

[88] 88 Fed. Reg. at 18,850.

[89] *See* EPA, National Pollutant Discharge Elimination System (NPDES), NPDES Application Forms, *available at* https://www.epa.gov/npdes/npdes-application-forms (last visited May 28, 2023).

County of Maui or, for that matter, instructs delegated states on how to do so.[90] In the absence of any of these necessary predicate actions, EPA's recommendations in the preamble for applicants to submit extensive "supplemental information" on potential CRL in groundwater, and thereafter to provide annual CRL monitoring reports, are wholly unsupported and inappropriate.

EPA claims that much of the supplemental data and information to be submitted with applications and included in annual reports is already available and thus "the incremental burden to facilities should be minimal,"[91] but this is not accurate. The recommended technical information extends far beyond what is required under EPA's CCR Rules. For example, EPA's CCR Rules do not require any of the information required to apply the Supreme Court's *County of Maui* factors (as proposed here), including travel time, pathway(s), or chemical fate and transport, as part of routine operational compliance. Moreover, EPA's CCR Rules only require characterization of the nature and extent of groundwater impacts for units that are subject to corrective action (i.e., those exceeding groundwater protection standards for Appendix IV constituents by statistically significant levels and for which an alternative source such as natural variability has not been identified). Therefore, the supplemental data and information EPA identifies for inclusion with applications is, in fact, not readily available.

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[90] In January 2021, EPA issued a guidance document interpreting and applying *County of Maui*. But in September 2021, EPA rescinded the guidance. We note that EPA apparently just submitted a proposed *Maui* implementation rule to OMB for review (https://www.reginfo.gov/public/jsp/EO/eoDashboard.myjsp [reginfo.gov]). However, the scope and details of the proposal have not yet been shared publicly so we have no basis to evaluate whether the approach here is consistent with the approach there. In addition, it would be procedurally improper for EPA to advance any particular *Maui* implementation approach through industry-specific ELGs without first proposing, taking comment on, and then finalizing its overall Maui implementation rulemaking.

[91] 88 Fed. Reg. at 18,889.

3. CRL ceases to be a waste stream—by definition—when it exits a unit.

As noted above, EPA proposes to maintain the 2015 definition of CRL, which is leachate that exits a CCR landfill or surface impoundment. CRL clearly is not the same as groundwater, which EPA defines as "water that is found in the saturated part of the ground underneath the land surface."[92] If CRL exits a unit and ends up in groundwater, then it necessarily becomes impacted groundwater.

EPA seems to assume that CRL retains some independent identity even after it mixes with groundwater, but this defies logic and lacks any limiting principles, the most obvious of which would be both spatial and temporal. In other words, CRL ceases to exist as a unique waste stream subject to the ELG program (or the CWA for that matter) once it exits a unit (e.g., through migration into groundwater). Similarly, CRL can no longer be considered CRL when it mixes with other media before, during or after the closure process. Otherwise, CRL-impacted groundwater could be subject to BAT limits (and EPA's presumptive pump-and-treat technology) long after a unit closes or at substantial distance from the unit. This proposal does not contemplate these definitional and practical limitations.

4. CRL in groundwater is governed by RCRA, not the CWA.

EPA's approach to CRL in groundwater also conflicts with – and threatens to undermine – EPA's comprehensive regulation of groundwater quality at CCR units through the CCR regulatory program under RCRA. In fact, EPA's proposal is fundamentally inconsistent with RCRA. In 2015, EPA adopted the first national regulations governing CCR as RCRA solid waste.[93] These regulations impose location restrictions,

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[92] 88 Fed. Reg. at 18,895 (Appendix A to the Preamble: Definitions, Acronyms and Abbreviations Used in this Preamble).

[93] *See* 80 Fed. Reg. 21,301 (Apr. 17, 2015).

design and operating criteria, groundwater monitoring and corrective action requirements, and closure and post-closure care requirements for regulated CCR units, including landfills and surface impoundments, as well as extensive recordkeeping, notification and public posting requirements, all of which are designed to meet the RCRA protectiveness standard of "no reasonable probability of adverse effects."[94] With respect to groundwater monitoring and corrective action, in particular, EPA's CCR Rules require compliance with groundwater protection standards and require remedial measures whenever Appendix IV constituents are detected in groundwater at statistically significant levels above those standards.[95] EPA's proposed BAT limits for CRL in groundwater bear no relation to these CCR groundwater protection standards, and EPA's presumed pump-and-treat approach[96] (assuming the groundwater is pumped for purposes of corrective action) circumvents the more comprehensive corrective action process required by the CCR rules. Furthermore, establishing effluent limits for groundwater impacted by CCR units could unnecessarily complicate or prolong corrective action under the federal CCR Rule at the site. Should EPA establish effluent limits for groundwater impacted by CRL, then EPA would introduce unnecessary uncertainty to the remedy selection process.

More fundamentally, EPA's proposed ELGs for CRL in groundwater threaten to disrupt the foundation of the RCRA CCR program. Congress defined "solid waste" in the statute to exclude point sources subject to

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[94] 42 U.S.C. § 6944(a).

[95] *See* 40 C.F.R. §§ 257.95 – 257.98.

[96] Included in the record for EPA's proposed supplemental ELGs is a memorandum dated March 2, 2023, entitled, "Evaluation of Potential CRL in Groundwater – DCN SE10250." The memo provides EPA's estimates for the maximum amount of groundwater potentially impacted by CRL and the rate at which groundwater would need to be pumped and treated to meet the proposed BAT limits. *See* Memorandum from U.S. EPA, Evaluation of Potential CRL in Groundwater – DCN SE10250 (Mar. 2, 2023) (Docket ID No. EPA-HQ-OW-2009-0819-9678). It is clear from this memo that EPA assumes pump-and-treat systems will be required to meet those limits.

NPDES permits under the CWA.[97] If EPA determines that CRL in groundwater is subject to ELGs implemented through NPDES permits, then CRL in groundwater will no longer be considered solid waste subject to RCRA, or more specifically, to the comprehensive CCR regulatory program (including groundwater corrective action). Congress could not possibly have intended for EPA to usurp its legislative prerogative in this manner.

Finally, in its brief and incomplete discussion of the CCR regulatory program,[98] EPA fails to meaningfully address significant pending CCR rulemakings and litigation over recent CCR determinations, all of which will affect the scope and applicability of the proposed ELGs. These include:

1. Legacy CCR surface impoundment rule (proposal published in the Federal Register on May 18, 2023);
2. Inactive landfill rule (this proposal has been consolidated with the legacy surface impoundment rulemaking identified above and further expanded to include other "non-containerized accumulations of CCR" including historical solid waste management units such as CCR landfills and surface impoundments that closed under then-existing law prior to the effective date of EPA's 2015 CCR Rule);[99]
3. Federal permit program rule (final expected in July 2023);
4. Part B, Part 2 rule (TBD);
5. Part A and B decisions and DC Circuit litigation (Pending).

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[97] *See* 42 U.S.C. § 6903(27).

[98] *See* 88 Fed. Reg. at 18,831.

[99] EPA's May 18, 2023, proposal would significantly expand the universe of regulated units subject to the CCR Rule but just as in this rulemaking, EPA wholly fails to address the ELG consequences. In fact, quite to the contrary, EPA says in the May 18 preamble that "there is no longer a need to coordinate with the ELG compliance deadlines." 88 Fed. Reg. at 31,996. This statement is demonstrably false insofar as the newly regulated CCR units – including legacy CCR surface impoundments and inactive CCR landfills – may generate CRL subject to the proposed BAT limits, even though they will be subject to nearly immediate closure requirements.

EPA cannot possibly impose BAT limits on CRL-impacted groundwater from unlined landfills and surface impoundments without fully understanding – or explaining to the public – the scope of the potentially regulated universe (which will not be determined, at the earliest, until items 1 and 2 above are proposed and finalized). Nor can EPA draw rational conclusions about how its proposed ELGs will affect units that are in the closure process – or the timing of closure – without fully understanding the outcome of items 3, 4, and 5 above. This is particularly problematic since the CCR Rules impose prescriptive closure deadlines with limited extension opportunities, all of which are directly implicated by EPA's newly proposed BAT limits and pump-and-treat requirements for CRL in groundwater. For all these reasons, EPA should withdraw its proposal to regulate CRL in groundwater. Doing so would be entirely consistent with EPA's approach to the landfill point source category in 2000.

B. EPA should not establish BAT or set effluent limits for CRL based upon the characteristics and treatment methods for FGD wastewater.

EPA solicits comment on whether it should establish BAT and set effluent limits for CRL based upon the characteristics and treatment methods for FGD wastewater. There are two key reasons why EPA should not pursue such an approach: 1) the two waste streams exhibit key differences that warrant different treatment; and 2) these two waste streams occur in entirely different settings, and for much different durations, relative to the life expectancy of the power plant itself.

Ultimately, both FGD wastewater and CRL result from combustion of coal. Therefore, there will be some similarities in the chemical composition of the waste streams. However, there are key differences in the waste stream chemical makeup that would allow a more cost-effective solution for CRL than is required for FGD wastewater. From a chemical standpoint, CRL is typically a much lower TDS waste stream than FGD wastewater with much lower concentrations of constituents that could necessitate different levels of treatment, such as selenium or nitrate. CRL typically contains selenium and nitrate at levels orders of magnitude lower than FGD wastewater, specifically making biological treatment a poor solution for CRL

compared to FGD wastewater. Unlike FGD wastewater, the production of CRL will long outlive the production of electricity at the plant. This fact should lead EPA toward considering more cost-effective options to effectively treat CRL. For at least these reasons, EPA should view the supporting basis for FGD wastewater limits and CRL limits as separate and distinct and should collect additional data as necessary to establish an appropriate BAT for CRL.

C. EPA should not pursue more stringent technology than chemical precipitation and should avoid establishing ZLD limits for CRL.

EPA should not pursue the use of more stringent technology such as biological or thermal systems for the treatment of CRL. As discussed, CRL should be viewed as separate and distinct from waste streams produced only during the operating life of the power plant itself, such as FGD wastewater. CRL is different in that the waste stream will be produced long into the future beyond the plant's active life of producing electricity. Biological and thermal systems pose significant operating, maintenance, and economic burdens to an operating plant, and even more so after a plant's retirement. Similarly, spray dryer evaporator (SDE) systems, which evaporate water by a heat source (typically from a slipstream of hot flue gas) are known to create hygroscopic salts from power plant waste streams that can quickly become a liquid under atmospheric conditions.

EPA is soliciting comment on whether ZLD limits should apply to CRL, and, if so, whether they should be based upon membrane filtration. As stated previously, we strongly encourage EPA to study and consider CRL as a separate waste stream from FGD wastewater and not simply transfer limitations from FGD wastewater to CRL. As a practical matter, we are not aware that EPA's technical administrative record would support such an approach. Additionally, achieving ZLD for a waste stream with a long-anticipated duration is an energy-intensive proposition. The energy required to maintain a ZLD of CRL will have to come from somewhere, even after a plant has ceased generating electricity. Landfills don't always exist

near the plant infrastructure. In some cases, landfills are located in relatively remote areas, which may be miles away from the plant operations. Given these settings, we encourage EPA to instead seek effective treatment systems with lower energy requirements and allow owners to reduce the leachate generated over time through appropriate landfill water management practices.

D. EPA should not set CRL limits for closed landfills or landfills at retired facilities.

CRL discharges from retired facilities or from landfills capped and closed prior to or within five years after promulgation of the rule should be exempt from further regulation and remain subject to the limits currently applied. Research shows that closed landfills have reduced CRL flows due to less rainfall that percolates through or drains from the materials placed in the landfill.[100] As the CRL flows decrease from closed landfills over time, the pollutant loadings decrease significantly. Likewise, in EPA's TDD for the proposed 2015 Rule, EPA provides the average CRL generation from active landfills is 65,500 gpd/plant, whereas the average CRL generation at retired landfills is 5,959 gpd/plant, less than 10% of active landfills.[101]

Annual CRL pollutant loadings for a closed landfill are provided in Table 2. Using EPA's flow rate for retired landfills and EPA's untreated CRL water quality data,[102] the pollutant loading per year for a closed

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[100] Electric Power Research Institute, Coal Combustion Residuals Leachate Management: Characterization of Leachate Quality and Evaluation of Leachate Minimization and Management Methods, 2015 Technical Report, 3002006283, at 3-4 (Dec. 2015).

[101] 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, at 6-13, Table 6-8 (Apr. 2013), (DCN SE01964) (EPA Docket ID No. EPA-HQ-OW-2009-0819-2257).

[102] EPA, Technical Development Document for the Proposed Supplemental Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category, EPA-821-R-23-005, at 61, Table 17 (Feb. 2023) (DCN SE10372) (Docket ID No. EPA-HQ-OW-2009-0819-9950).

landfill is 56,333 lbs/year and using EPA's toxicity weighting factors,[103] the loading per plant would be 38 TWPE/year or toxic-weighed pounds per equivalent/year. These numbers are significantly different with EPA's estimate of approximately 980,000 lbs/year at each operating plant.[104] EPA states that the pollutant loadings were calculated as the sum of TDS and TSS. Most of the TDS constituents discharged from CRL include sulfate, chloride, calcium, and sodium, which are not considered toxic and have not been assigned toxic weighing factors by EPA. Therefore, the lower flows and smaller quantity of pollutant loadings in CRL at closed landfills does not justify substantial capital cost investments for chemical precipitation.

In addition, when developing ELGs, the CWA requires EPA to consider the age of facilities involved and the cost of achieving effluent reduction. The costs of achieving the proposed BAT limits for CRL discharges at *retired* facilities would be much higher than compliance costs at *operating* facilities. EPA's cost estimates for CRL BAT (chemical precipitation), assuming an average flow rate of 63 gallons per minute (gpm), is $11.2 million capital, $0.65 million annual O&M, and $1.7 million annualized cost.[105] At a retired facility, the cost of power, labor, and residuals management and disposal is expected to be higher due to additional costs to bring power to the facility where no power is being generated onsite, the cost of a wastewater treatment operator who will work exclusively on the treatment system, and higher transportation and disposal costs for residuals management.[106]

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[103] EPA, Regulatory Impact Analysis for the Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category, EPA-821-R-15-004, at Appendix F (Sept. 2015) (DCN SE07620) (Docket ID No. EPA-HQ-OW-2009-0819-7549).

[104] EPA, 2023 Technical Development Document, *supra* note 102, at 63, Table 20 (baseline 67,700,000 lbs/year divided by 69 plants).

[105] EPA assumed 7% interest rate and 20-year life for annualized cost.

[106] EPRI Comments, *supra* note 43, at 69.

Table 2. CRL Pollutant Loadings from Closed Landfills

Pollutant	Toxic Weighted Factor	Untreated CRL[1]	Pollutant Loading[2]	
		Average Conc. (µg/L)	lbs/year	TWPE/yr
Total Suspended Solids		35,800	649	
Total Dissolved Solids		3,500,000	63,435	
Priority Pollutants				
Antimony	0.01225	3.75	0.1	0.0
Arsenic	4.04133	38.4	0.7	2.8
Cadmium	23.11680	10.1	0.2	4.2
Chromium	0.07570	2,120	38.0	3.0
Copper	0.63482	7.58	0.1	0.1
Mercury	117.11802	1.06	0.0	2.3
Nickel	0.10891	46.5	0.8	0.1
Selenium	1.12134	111	2.0	2.0
Thallium	1.02706	1.16	0.0	0.0
Zinc	0.04689	211	4.0	0
Non-conventional Pollutants				
Aluminum	0.06469	2,990	54	4.0
Barium	0.00199	53.2	1.0	0.0
Boron	0.00834	22,400	406	3.0
Calcium	0.00003	408,000	7,395	0
Chloride	0.00002	413,000	7,485	0
Cobalt	0.11429	38.6	0.7	0.1
Iron	0.00560	37,100	672	4.0
Magnesium	0.00087	118,000	2,139	2.0
Manganese	0.07043	2,720	49	3.0
Molybdenum	0.20144	1,380	25	5.0
Sodium	0.00001	308,000	5,582	0
Sulfate	0.00001	1,790,000	32,442	0
Vanadium	0.03500	1,910	35	1.0
TOTAL (TSS and TDS Only)			**64,084**	**N/A**
TOTAL (all except TSS and TDS)			**56,333**	**38.0**

[1] Untreated CRL water quality obtained from Table 17 of 2023 TDD.

[2] Annual pollutant loading calculated using pollutant concentration and retired CRL daily flow obtained from Table 6-8 of the 2013 TDD multiplied by 365 days.

But EPA has not considered these costs. Therefore, in recognition of the age of the facilities and the cost of chemical precipitation, EPA should exclude retired facilities from the new CRL BAT limits or develop a new proposal that adequately assesses the potential regulatory impact on retired facilities.

E. EPA should update its population of landfills that collect and discharge CRL and the total industry costs to comply with the proposed CRL limits based on chemical precipitation.

EPA has underestimated the number of landfills that collect and discharge CRL and the total industry costs to treat CRL with chemical precipitation technology to meet proposed mercury and arsenic limits. Table 12, *Estimated Cost of Implementation for Combustion Residual Leachate by Regulatory Option (in Millions of Pre-tax 2021 Dollars)*, in the 2023 TDD[107] includes 69 facilities that EPA has identified as the population of landfills containing CCRs that collect and discharge CRL to surface waters or POTWs. Also, Table 10 in EPA's memorandum, *Generating Unit-Level Costs and Loadings Estimates by Regulatory Option for the 2023 Proposed Rule (SE10381)*, provides costs for chemical precipitation treatment of CRL for 69 facilities. Later in its analysis, EPA found 65 additional facilities that have constructed new landfills since 2015 using data from utilities' "CCR Rule Compliance Data and Information" websites[108] but apparently did not include these facilities in their industry cost estimates. EPA needs to include these additional 65 landfills in its overall costs to the industry. The addition of these 65 facilities to EPA's cost estimates is more than likely to double the costs of CRL treatment to the industry. EPA needs to add these

[107] EPA, 2023 Technical Development Document, *supra* note 102, at 52, Table 12.

[108] Memorandum from U.S. EPA, Evaluation of Potential CRL in Groundwater, *supra* note 96.

costs into its total industry costs and rerun all its models to account for these additional costs, including the missing costs identified for FGD wastewater Option 3 compliance.

VII. CONCLUSION

Southern Company is committed to building the future of energy for the advancement of our customers and communities. We are focused on transitioning our generating fleet to net zero greenhouse gas emissions and making the necessary related investments in our transmission and distribution grids, while maintaining reliability and affordability for our customers. EPA's recently proposed Supplemental ELG Rule threatens to disrupt the orderly fleet transition by increasing risks to reliability while burdening customers with undue costs. While The Southern Company is committed compliance with environmental laws, the realities of cost and reliability concerns in serving our customers cannot be ignored. We encourage EPA to finalize a Supplemental ELG Rule that can protect the environment, promote resiliency and reliability of the electric power system, and help to alleviate a significant cost burden to customers. We look forward to engaging constructively with EPA on this and future rulemakings.

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APPENDIX A

Alabama Power Company - Plant Miller Membrane Cost Study

First Page – Total Project Cost

WesTech Budgetary Study Report

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Miller ELG - Screening **2/23/2023**

DIVISION OF WORK (DOW)

PRELIMINARY ESTIMATE - REVIEW & SIGN-OFF REQUIRED

Item Description	Qty	Unit	Labor Hours	Labor Total	Matl Total	Subs Hours	Subs Total	Engr Total	Engr Exp Total	Total Costs
Engineering	**0**	**HR**		**$0**	**$0**	**0**	**$0**	**$15,679,017**	**$0**	**$15,679,017**
CECEN285 - Design & Technical Services - Detailed Engineering	0	HR		$0	$0	0	$0	$2,679,017	$0	$2,679,017
CECEN291 - Outsourced Detailed Engineering	0	HR		$0	$0	0	$0	$13,000,000	$0	$13,000,000
Construction	**0**	**HR**	**211,107**	**$73,362,741**	**$81,559,302**	**0**	**$478,170**	**$6,123,468**	**$0**	**$161,523,681**
COCIN150 - T&PS - Construction Management	0	HR		$0	$0	0	$0	$3,827,167	$0	$3,827,167
COCIN151 - Temporary Construction	0	HR		$0	$0	0	$0	$2,296,300	$0	$2,296,300
COCPK001 - Underground Investigations / Site Work			11,898	$494,608	$0	0	$0	$0	$0	$494,608
COCPK006 - Mechanical			0	$58,003,045	$76,223,647	0	$0	$0	$0	$134,226,692
COCPK012 - Demolition			199,209	$9,434,339	$0	0	$478,170	$0	$0	$9,912,510
COCPK030 - Contractor Indirects			0	$5,430,748	$5,335,655	0	$0	$0	$0	$10,766,403
Start Up	**0**	**HR**	**0**	**$0**	**$0**	**0**	**$0**	**$7,390,867**	**$0**	**$7,390,867**
TSSUC750 - Start-up and Commissioning	0	HR	0	$0	$0	0	$0	$1,530,867	$0	$1,530,867
TSSUC752 - Outsourced Start-Up and Commissioning	0	HR	0	$0	$0	0	$0	$5,860,000	$0	$5,860,000
Owner	**0**	**HR**	**0**	**$2,443,052**	**$2,716,005**	**0**	**$15,924**	**$972,167**	**$0**	**$6,147,147**
CPCOC301 - E&S				$2,443,052	$2,716,005		$15,924	$972,167	$0	$6,147,147
Escalation and Contingency				**$16,126,325**	**$17,928,063**	**0**	**$105,110**	**$6,417,174**	**$0**	**$40,576,671**
CPCOC304 - Escalation				$1,453,777	$1,616,202		$9,476	$578,504	$0	$3,657,958
CPCOC305 - Contingency				$14,672,548	$16,311,860		$95,634	$5,838,670	$0	$36,918,713
AFUDC				**$15,101,617**	**$16,788,867**	**0**	**$98,431**	**$6,009,410**	**$0**	**$37,998,325**
CPCOC300 - AFUDC/IDC				$15,101,617	$16,788,867		$98,431	$6,009,410	$0	$37,998,325
TOTAL PROJECT COST	**0**	**HR**	**211,107**	**$107,033,734**	**$118,992,237**	**0**	**$697,634**	**$42,592,103**	**$0**	**$269,315,708**

Total Craft Hours 211,107

Temporary Bio Rental (2.5 years from 2019 proposal)	$ 3,160,000
ECO Materials contract buyout	6,600,000
Total	$279,075,708



Alabama Power

Plant Miller VIP – Budgetary Study

Location

Alabama Power James H. Miller
Generating Station
4250 Porter Rd. Quinton, AL 35130

Contact

Dallas Torgersen
dtorgersen@westech-inc.com
801.290.1921

Owner

Southern Company

Representative

Lawson Craig
Lawson@pureprocess.co
265.260.3967

WesTech®

Project Number: 24877
Wednesday, February 22, 2023

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Technical Proposal

Design Basis

The objective of this document is to provide Southern Company Services with a conceptual design and budgetary level cost estimate of certain deliverables associated with converting Alabama Power Company's existing flue gas desulfurization (FGD) wastewater treatment system at Plant Miller to comply with revised discharge limits for the treatment of FGD wastewater expected in EPA's forthcoming Effluent Limitations Guideline (ELG) Supplemental Rule. Alabama Power previously installed "chemical precipitation + low hydraulic residence time biological treatment" at Plant Miller for the treatment of FGD wastewater. The treatment system is designed to comply with EPA's 2015 and 2020 ELGs.

This document assumes EPA's new FGD wastewater discharge limits will be identical to the Voluntary Incentives Program (VIP) limits included in the agency's 2020 ELG rule and delineates a cost estimate for certain elements necessary for the installation of membrane filtration technologies (i.e., the "Process Island Costs").

Reference Standards & Codes

- ANSI/ASME American Society of Mechanical Engineers B31.1 Power Piping Code
- American Institute of Steel Construction (AISC) specification for the Design, Fabrication and Erection of Structural Steel for Buildings
- AWS - American Welding Society: D1.1 - "Structural Welding Code - Steel".
- American Iron and Steel Institute (AISI) specification for the Design of Light Gauge Cold-Formed Steel Structural Members
- NEMA - National Electrical Manufacturers Association: MG 1 - "Motors and Generators".
- American Concrete Institute (ACI) Building Code requirements for reinforced Concrete ACI 318-63
- AISC Manual of Steel construction
- ASME B16.5 Pipe Flanges and Flanged Fittings
- ASME B30-2 Overhead and Gantry Cranes
- Underwriters Laboratories (UL): 10B - "Standard for Safety Fire Tests of Door Assemblies".
- NEC National Electric Code
- NFPA - National Fire Protection Association:
  - 70 - "National Electrical Code".
  - 80 - "Standard for Fire Doors and Fire Windows".
  - 101 – "Life Safety Code".

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- U.S. Department of Labor, Occupational Safety and Health Administration (OSHA): 29 CFR, Title 29 - "Occupational Safety and Health Standards".

Governing codes for project location:

- 2006 International Building Code with Georgia amendments.
- Including and not limited to verifying and designing for the Seismic Site Class in accordance with IBC Section 1615.
- NFPA 101 – "Life Safety Code for Buildings".
- OSHA - Occupational Safety and Health Administration.

WesTech General Specifications

- D-11 DESIGN FUNCTIONAL TAGS AND DESCRIPTIONS
- FIELD LINING SPECIFICATION
- PAINT COLOR GUIDANCE
- PAVEMENT STRUCTURES
- PREFERRED VENDOR LIST
- M_2_09 MECHANICAL INSULATION

WesTech Electrical Specifications

BGE Drawings

- BGE1001
- BGE1003
- BGE1004
- BGE1005
- BGE1006
- BGE1007
- BGE1008
- BGE1011

Electrical Standards

- E-1-02 Raceway Naming
- E-1-03 Raceway Design Standard
- E-1-04 Circuit Naming

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- E-1-05 Plant Circuitry
- E-1-06 Cable and Cable Bus
- E-1-07 Transformers
- E-1-08 Direct Current Distribution Systems Standard
- E-1-09 Fuses
- E-1-10 Lighting and Receptacles
- E-1-11 Grounding Standard
- E-1-13 Hazardous Classified Locations
- E-2-03 Cable Code Definition
- E-2-04 Electrical Mark Numbers
- E-2-10 Arc Flash Mitigation (1)

Installation Standards

- Standard_Spec_SECTION_260000_Gen_Req
- Standard_Spec_SECTION_260526_grounding_system
- Standard_Spec_SECTION_260533_conduit
- Standard_Spec_SECTION_261213_outdoor_xfrmers
- Standard_Spec_SECTION_262716_boxes
- Standard_Spec_SECTION_265000_lighting_fixtures
- Standard_Spec_SECTION_266010_motors
- Standard_Spec_SECTIONS_2605xx_electrical_cables

Other Specifications

- Cable Specification
- G95797 LV MCC Detailed Spec
- G95797 LV MCC General Spec
- Heat Tracing Specification

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Process Design

Below is a table of the influent water process design criteria provided as part of the request for quotation. This process stream will discharge from the Plant's existing FGD wastewater physical/chemical (phys/chem) treatment system and feed the new Membrane Treatment System (MTS).

Table 1. Influent Design Criteria Values

Influent Design Criteria (to MTS)				
Parameter	**Units**	**Normal (Cycled Down, Typ. Values, 50% Flow)**	**Design Case 1 (Cycled Down, Max. Values, 100% Flow)**	**Design Case 2 (Cycled Up, Max. Values, 100% Flow)**
Flow, total leaving Phys/Chem	gpm	304	608	608
Flow, portion feeding VSEP	gpm	304	608	150
Total Dissolved Solids (TDS)	mg/L	8,000	10,000	35,000
pH	S.U.	6.7	5.5 – 8.5	5.5 – 8.5
Total Suspended Solids (TSS)	mg/L	6.4	50	50
Oil & Grease	mg/L	<1	<1	<1
As, total	µg/L	2.5	5	12
Hg, total	ng/L	2,500*	10,000**	15,000***
Nitrates/Nitrites	mg/L as N	20	30	75
Se, total	µg/L	500	1,000	2,000
Chloride	mg/L	3,000	3,000	15,000
Bromide	mg/L	30	30	240
Calcium, total	mg/L as CaCO3	1,000	1,500	3,000
Magnesium, total	mg/L as CaCO3	1,500	1,500	5,000
Temperature	Deg F	50 - 120	50 - 120	50 - 120

Notes:
* Typical cycled down range for total mercury ranges from 200 to 3,000 ng/L
** Cycled down operation can range up to 6,500 ng/L with occasional, isolated spikes up to 10,000 ng/L.
*** Typical cycled up range is 5,000 to 9,000 ng/L with occasional isolated spikes up to 15,000 ng/L

The treatment system proposed herein is designed in accordance with the Design Case 1 constituent levels and maximum flowrate (608 gpm). This design case reflects conditions observed when all the FGD scrubber systems are cycled down and all treated effluent is discharged to the river. All brine generated is encapsulated, with no water returning to the FGD scrubbers as make-up water.

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The performance of the proposed system has been evaluated at the Design Case 2, which reflects maximum cycled up values. This scenario reflects the recycling of the majority of treated effluent from the existing physical/chemical system back to the FGD scrubbers as makeup water. The remaining water is sent to the membrane system (150 gpm). All effluent from the membrane system is discharged to the river and all brine generated in the evaporators is encapsulated. Please refer to Item A – VSEP Membranes and Spiral Reverse Osmosis (RO) Membrane Systems for detailed equipment design information.

The following table outlines effluent performance criteria for the Membrane Treatment System discharges.

Table 2. Membrane System Effluent Values (Permeate and Distillate Stream)

Membrane System Effluents (Permeate and Distillate Stream)			
Parameter	**Units**	**Maximum for any 1 Day**	**Maximum Rolling 30 Day Average**
Total Dissolved Solids (TDS)	mg/L	306	149
pH	S.U.	6 - 9	6 - 9
As, total	µg/L	5	NA
Hg, total	ng/L	23	10
Nitrates/Nitrites	mg/L as N	2	1.2
Se, total	µg/L	10	NA
Bromide	mg/L	0.2	NA

Note that these effluent limits are assumed from the 2020 ELG VIP for reference only and do not constitute a process guarantee. WesTech can provide a formal process guarantee upon request.

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Assumptions

- The existing physical / chemical treatment will remain in service as pre-treatment ahead of the new Membrane Treatment System.
- The existing Biological Treatment System (BTS) may be decommissioned and removed.
- The existing Biological Treatment System ultrafiltration (UF) clean-in-place (CIP) system will not be removed if further analysis reveals this existing equipment can be reused in the new system.
- Unless otherwise stated, all subsystems and modular components will be provided as manufacturer's standard and will not follow any additional custom specifications.

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Plant Design

Table 3. List of Major Equipment Vendors

Major Equipment Vendors	
Type	**Vendor**
Vibrating Membranes (VSEP)	New Logic Research
Spiral RO Membranes	New Logic Research
Thermal Evaporator (AVARA)	Purestream
Solidification Equipment	Jamieson Equipment Company
Process Pumps	Grundfos, or Equal
Chemical Metering Pumps	Grundfos, or Equal
PLC	Allen Bradley or Equal
Butterfly Valves	Bray or Equal
Ball Valves	Flow-Tek or Equal
Analytical Instrumentation	Endress+Hauser or Equal
Pressure Instrumentation	Endress+Hauser or Equal
Flow Instrumentation	Endress+Hauser or Equal
Level Instrumentation	Endress+Hauser or Equal

*Final vendor selections may differ based on detailed engineering. WesTech may utilize an 'or equal' if needed.

Sparing Philosophy

In general, WesTech will provide equipment with 2 x 50% sparing. Equipment not in 2 x 50% trains will at minimum treat 100% of design flow with expected equipment under routine cleaning (CIP), and will treat a minimum of 50% of design flow in all cases.

Pumps

- ASME B73 or pump manufacturer standards will be considered, as applicable.

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Piping

Table 4. Plant Miller Piping Summary Design Basis

Piping Summary	
Service	**Pipe Material**
Process, Above Ground, Inside	HDPE
Process, Above Ground, Outside	HDPE
Process, Underground,	HDPE
Process, Underground, Treated, Outfall	HDPE
Process, Underground, Treated, Outfall	HDPE
Process, Above Ground, Skidded Materials	2205
Process, Above Ground, Inside, MTS Boundary Limits	2205
Chemical, Hydrogen Peroxide	Tube: PVDF
Chemical, Ferric Chloride	Tube: Polypropylene (CPVC on Skid)
Chemical, Sodium Hydroxide	Tube: Polypropylene (CPVC on Skid)
Chemical, Sulfuric Acid	Tube: PVDF
Chemical, Organosulfide	Tube: Polypropylene (CPVC on Skid)
Chemical, Ferric Sulfate	Tube: Polypropylene (CPVC on Skid)
Chemical, Sodium Sulfate	Tube: Polypropylene (CPVC on Skid)
Chemical, Sodium Bisulfite	Tube: Polypropylene (CPVC on Skid)
Polymer, <= 1/2-in.	Tube: Polypropylene (CPVC on Skid)
Polymer, > 1/2-in.	Tube: Polypropylene (CPVC on Skid)
Service Water	CS
Air, Service, >= 1/2-in.	304SS
Air, Instrument, >= 1/2-in.	304SS
Air, Instrument, < 1/2-in. (Pressure Regulated)	Tube: 304SS (SwageLok)
Potable Water, Above Ground, Inside, < 2-in	Copper
Potable Water, Underground	HDPE
Fire Water, Inside, Sprinkler	CS
Sewer	HDPE

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Battery Limits

The following tie points have been identified and will be specified with generalized (not to exceed) conditions for the purposes of developing engineering. The purchaser will be responsible for providing not to exceed values where indicated in the table below. Final tie point conditions will be identified in the Tie Point List which will be provided by WesTech with a 30% engineering package.

Table 5. Plant Miller Battery Limit Tie Points

Tie Points						
#	**Tie-Point**	**Max Flow (GPM)**	**Max Pressure (ft H2O)**	**Location**	**Grade Elevation (ft)**	**Connection Type**
1	Inlet to Influent Pump Skid	608	TBD	BTS Pad	TBD	FF, ANSI 150
	Note 1: Connection within 10’ of the WWTS boundary					
2	Final Effluent to Existing pipeline to FGD Effluent Tank	520	TBD	BTS Pad	TBD	FF, ANSI 150
	Note 1: Connection within 10’ of the WWTS boundary					
3	AVARA Brine Final Effluent	23.1	TBD	TBD	TBD	FF, ANSI 150
	Note 1: Connection within 10’ of the WWTS boundary					
4	Service Water	21	TBD	BTS Pad	TBD	FF, ANSI 150
	Note 1: Connection within 10’ of the WWTS boundary					
5	Sumps					
	Note 1: Effluent from any drain lines from the proposed system to the two (2) existing sumps on the BTS pad are to serve as a project boundary. WesTech has not included any sumps within this study.					
6	Compressed Air					
	Note 1: At BTS Pad. VSEP requirements are 66 CFM.					
7	Electrical			Note 1		
	Note 1: WT will determine location on field wiring plans (preliminary) with an engineering package after execution of the contract. Other: WT will supply a 480V 3PH 60 HZ distribution panel for all loads inside the battery limits of the WWTS. Purchaser will be responsible for powering this panel based on not to exceed loads that will be provided on the single line diagram with an engineering package after execution of contract.					
8	Communication			Note 1		
	Note 1: WT will determine location on field wiring plans (preliminary) with an engineering package after execution of the contract Other: Tie points will be at WT supplied PLC. Purchaser will be responsible for communication cable with any systems outside of 10’ of WesTech’s treatment boundary.					

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Site Information

Table 6. Plant Miller Site Specific Information

Operating Company	Alabama Power Company		
Plant	Plant J.H. Miller		
Units	1-4		
Street Address	4250 Porter Road		
City	Quinton		
County	Jefferson		
State	Alabama		
Zip Code	35130-9471		
Coordinates	Longitude:	87.06038º West	
	Latitude:	33.63420º North	
Grade Elevation	306’-0” ASL		
Railroad Access	Yes (Burlington Northern and Norfolk Southern)		
Barge Access	No		
	Minimum	**Typical**	**Maximum**
Ambient Temperature (ºF)	-10	75	107
Indoor Temperature (ºF)	45	90	110
Ambient Relative Humidity (%)	30	60	100
Barometric Pressure (psia)		14.535	
Average Monthly Rainfall (in)		4.67	
Max. Daily Rainfall (25yr/24hr, in)			7.11
Max. Single Rainfall Event (10yr/2hr, in)			3

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Scope Split

Table 7. Plant Miller Project Execution Scope Matrix

Scope Matrix				
Work Category	**Functional Design/Input**	**Detailed Design**	**Supply**	**Install/ Perform**
Equipment Supply	WesTech	WesTech	WesTech	3rd Party Construction Contractor
Earthwork	WesTech	WesTech	3rd Party Construction Contractor	3rd Party Construction Contractor
Concrete	WesTech	WesTech	3rd Party Construction Contractor	3rd Party Construction Contractor
Interconnecting Piping (plant)*	WesTech	WesTech	3rd Party Construction Contractor	3rd Party Construction Contractor
Interconnecting piping (to plant)**	Owner	Owner	Owner	Owner
Interconnecting Wiring*	WesTech	WesTech	3rd Party Construction Contractor	3rd Party Construction Contractor
Interconnecting Wiring (to plant)**	Owner	Owner	Owner	Owner
Main Power Distribution	WesTech	WesTech	3rd Party Construction Contractor	3rd Party Construction Contractor
Transformer	WesTech	Owner	Owner	Owner
MCC	WesTech	WesTech	WesTech	3rd Party Construction Contractor
PLC	WesTech	WesTech	WesTech	3rd Party Construction Contractor
Temporary Structures	WesTech	WesTech	3rd Party Construction Contractor	3rd Party Construction Contractor
Permitting	WesTech	WesTech	Owner	Owner

*Within boundary limits of the plant

**Outside boundary limits of the plant (See Battery Limits)

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Process Flow Diagram

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CHEMICAL LEGEND:
C1 - ACID
C2 - ANTISCALANT
C3 - BISULFITE
C4 - CIP LOW PH
C5 - CIP HIGH PH

PFD 3
STAGE 3 RO CONCENTRATE

MULTI MEDIA FILTER EFFLUENT

TP 1

INFLUENT PUMP SKID

C1

STAGE 1 LOW PRESSURE VSEP FEED TANK

C2 C3

STAGE 1A-1G VSEP FEED PUMP AND BOOSTER PUMP SKID X 7

C4 C5

8 MEMBRANES PER SKID

F P C

STAGE 1A-1G LOW PRESSURE VSEP MEMBRANES SKID X 7

STAGE 3 SPIRAL RO FEED TANK

STAGE 2 HIGH PRESSURE VSEP FEED TANK

NOTE 2

NEW LOGIC STAGE 1 PACKAGE

NOTES:

1. FOLLOW THE LISTED WESTECH REFERENCE DOCUMENTS EXCEPT AS NOTED ON THIS DRAWING
2. IF CHLORIDE CORROSION BECOMES A CONCERN STAGE 1 MAY USE TWO FEED PUMPS INSTEAD OF TWO BOOSTER PUMPS AND TWO FEED PUMPS.

REV	REVISION DESCRIPTION	ECN	DESIGNER	APPROVER	DATE	REFERENCE DOCUMENTS
A	FOR INFORMATION ONLY	XX	SO74	MU20	2023-02-07	################

PREPARED FOR PLANT MILLER
FGD WASTEWATER VSEP TREATMENT CONVERSION
QUINTON, ALABAMA
ENGINEER: WESTECH ENGINEERING, LLC
SALT LAKE CITY
CONTRACTOR: WESTECH ENGINEERING, LLC
SALT LAKE CITY, UTAH
JOB NUMBER: 24877

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TITLE **PROCESS FLOW DIAGRAM**
STAGE 1

CLIENT DOCUMENT NUMBER			
24877A-PR-PFD-01			
DESIGNER	CHECKER	APPROVER	DATE
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JOB NUMBER	DOCUMENT NUMBER	SHEET	REV
24877A	**XXX**	1 OF 9	**A**

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CHEMICAL LEGEND:
C1 - ACID
C2 - ANTISCALANT
C3 - BISULFITE
C4 - CIP LOW PH
C5 - CIP HIGH PH

PFD 1
STAGE 1 LOW PRESSURE VSEP CONCENTRATE

STAGE 2 HIGH PRESSURE VSEP FEED TANK

C2

STAGE 2A-1D VSEP FEED PUMP AND BOOSTER PUMP SKID X 4

C4 C5

4 MEMBRANES PER SKID

F P C

STAGE 2A-2D HIGH PRESSURE VSEP MEMBRANES SKID X 4

STAGE 3 SPIRAL RO FEED TANK

CONCENTRATE STORAGE TANK

NEW LOGIC STAGE 2 PACKAGE

REV	REVISION DESCRIPTION	ECN	DESIGNER	APPROVER	DATE	REFERENCE DOCUMENTS
A	FOR INFORMATION ONLY	XX	SO74	MU20	2023-02-07	################

PREPARED FOR PLANT MILLER
---- FGD WASTEWATER VSEP TREATMENT CONVERSION
---- QUINTON, ALABAMA

ENGINEER: WESTECH ENGINEERING, LLC
---- SALT LAKE CITY

CONTRACTOR: WESTECH ENGINEERING, LLC
---- SALT LAKE CITY, UTAH

JOB NUMBER: 24877

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TITLE **PROCESS FLOW DIAGRAM**
STAGE 2

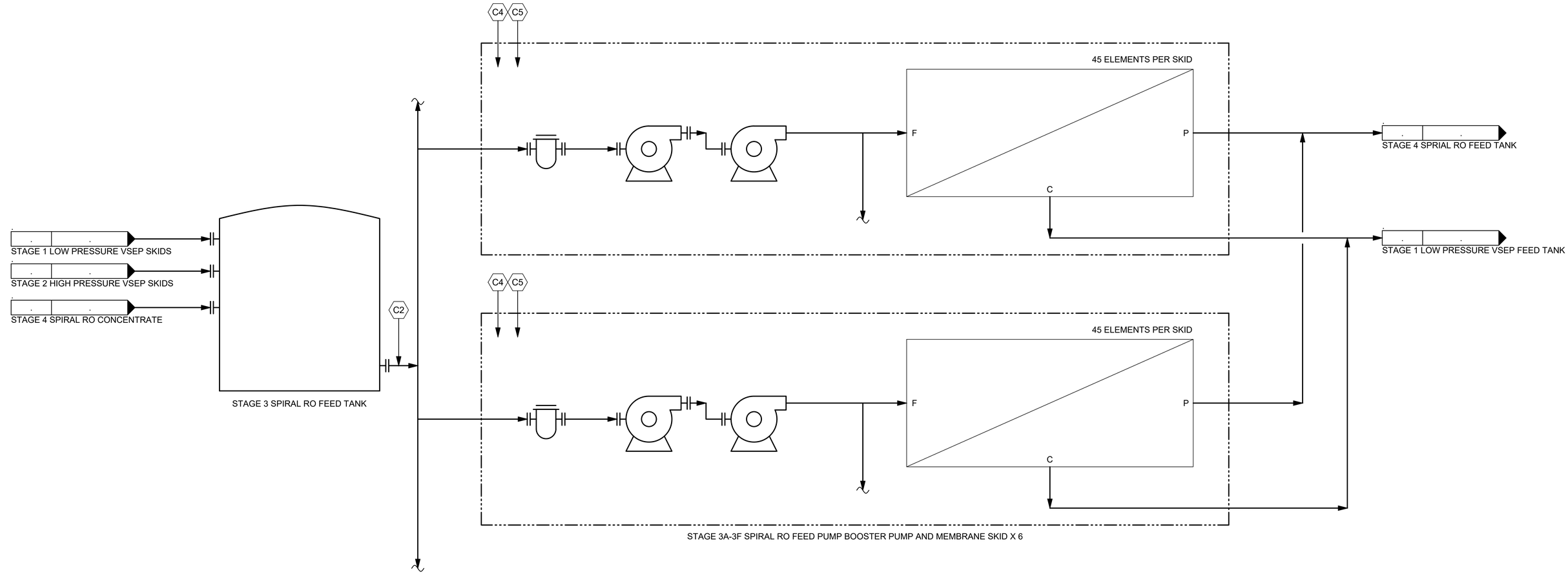
CLIENT DOCUMENT NUMBER: **24877A-PR-PFD-01**

DESIGNER	CHECKER	APPROVER	DATE
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JOB NUMBER	DOCUMENT NUMBER	SHEET	REV
24877A	**XXX**	2 OF 9	**A**

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CHEMICAL LEGEND:
C1 - ACID
C2 - ANTISCALANT
C3 - BISULFITE
C4 - CIP LOW PH
C5 - CIP HIGH PH



REV	REVISION DESCRIPTION	ECN	DESIGNER	APPROVER	DATE	REFERENCE DOCUMENTS
A	FOR INFORMATION ONLY	XX	SO74	MU20	2023-02-07	################
						################

PREPARED FOR	PLANT MILLER
----	FGD WASTEWATER VSEP TREATMENT CONVERSION
----	QUINTON, ALABAMA
----	----
ENGINEER:	WESTECH ENGINEERING, LLC
----	SALT LAKE CITY
----	----
CONTRACTOR:	WESTECH ENGINEERING, LLC
----	SALT LAKE CITY, UTAH
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JOB NUMBER:	24877
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TITLE **PROCESS FLOW DIAGRAM**
STAGE 3

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DESIGNER	CHECKER	APPROVER	DATE
----	----	----	----

JOB NUMBER	DOCUMENT NUMBER	SHEET	REV
24877A	**XXX**	3 OF 9	**A**

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CHEMICAL LEGEND:
C1 - ACID
C2 - ANTISCALANT
C3 - BISULFITE
C4 - CIP LOW PH
C5 - CIP HIGH PH

C4 C5

45 ELEMENTS PER SKID

F P C

STAGE 5 SPIRAL RO FEED TANK

STAGE 3 SPIRAL RO FEED TANK

STAGE 3 SPIRAL RO PERMEATE

STAGE 5 SPIRAL RO CONCENTRATE

STAGE 4 SPIRAL RO FEED TANK

C4 C5

45 ELEMENTS PER SKID

F P C

STAGE 4A-4F SPIRAL RO FEED PUMP BOOSTER PUMP AND MEMBRANE SKID X 6

REV	REVISION DESCRIPTION	ECN	DESIGNER	APPROVER	DATE	REFERENCE DOCUMENTS
A	FOR INFORMATION ONLY	XX	SO74	MU20	2023-02-07	################
						################

PREPARED FOR PLANT MILLER
---- FGD WASTEWATER VSEP TREATMENT CONVERSION
---- QUINTON, ALABAMA
---- ----
ENGINEER: WESTECH ENGINEERING, LLC
---- SALT LAKE CITY
---- ----
CONTRACTOR: WESTECH ENGINEERING, LLC
---- SALT LAKE CITY, UTAH
---- ----
JOB NUMBER: 24877
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TITLE **PROCESS FLOW DIAGRAM**
STAGE 4

CLIENT DOCUMENT NUMBER: **24877A-PR-PFD-01**

DESIGNER	CHECKER	APPROVER	DATE
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JOB NUMBER	DOCUMENT NUMBER	SHEET	REV
24877A	**XXX**	4 OF 9	**A**

G:\ACTVJOBS\24800JOBS\24877A PLANT MILLER VIP – ENGINEERING STUDY, AL\DRAWINGS\24877A_PLANT MILLER_1.0\PID DWG\24877A-PR-PFD-01

CHEMICAL LEGEND:
C1 - ACID
C2 - ANTISCALANT
C3 - BISULFITE
C4 - CIP LOW PH
C5 - CIP HIGH PH

AVARA DISTALLATE

STAGE 4 SPIRAL RO PERMEATE

STAGE 5 SPIRAL RO FEED TANK

C4 C5

45 ELEMENTS PER SKID

F P C

C4 C5

45 ELEMENTS PER SKID

F P C

STAGE 5A-5F SPIRAL RO FEED PUMP BOOSTER PUMP AND MEMBRANE SKID X 6

PERMEATE FORWARDING STORAGE TANK

PERMEATE FORWARDING PUMP SKID

TP 2

3

FGD EFFLUENT TANK

STAGE 4 SPIRAL RO FEED TANK

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A	FOR INFORMATION ONLY	XX	SO74	MU20	2023-02-07	################
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PREPARED FOR PLANT MILLER
---- FGD WASTEWATER VSEP TREATMENT CONVERSION
---- QUINTON, ALABAMA
---- ----
ENGINEER: WESTECH ENGINEERING, LLC
---- SALT LAKE CITY
---- ----
CONTRACTOR: WESTECH ENGINEERING, LLC
---- SALT LAKE CITY, UTAH
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JOB NUMBER: 24877
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TITLE **PROCESS FLOW DIAGRAM**
STAGE 5

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JOB NUMBER	DOCUMENT NUMBER	SHEET	REV
24877A	**XXX**	5 OF 9	**A**

Appellate Case: 24-2123 Page: 107 Date Filed: 07/26/2024 Entry ID: 5417837

CHEMICAL LEGEND:
C1 - ACID
C2 - ANTISCALANT
C3 - BISULFITE
C4 - CIP LOW PH
C5 - CIP HIGH PH

STAGE 2 HIGH PRESSURE VSEP CONCENTRATE

CONCENTRATE STORAGE TANK

AVARA EVAPORATOR SYSTEM X 3
(INCLUDES FEED PUMPS, HEAT EXCHANGERS, BRINE PUMP)

PERMEATE FORWARDING STORAGE TANK

BRINE STORAGE TANK (BY OTHERS)

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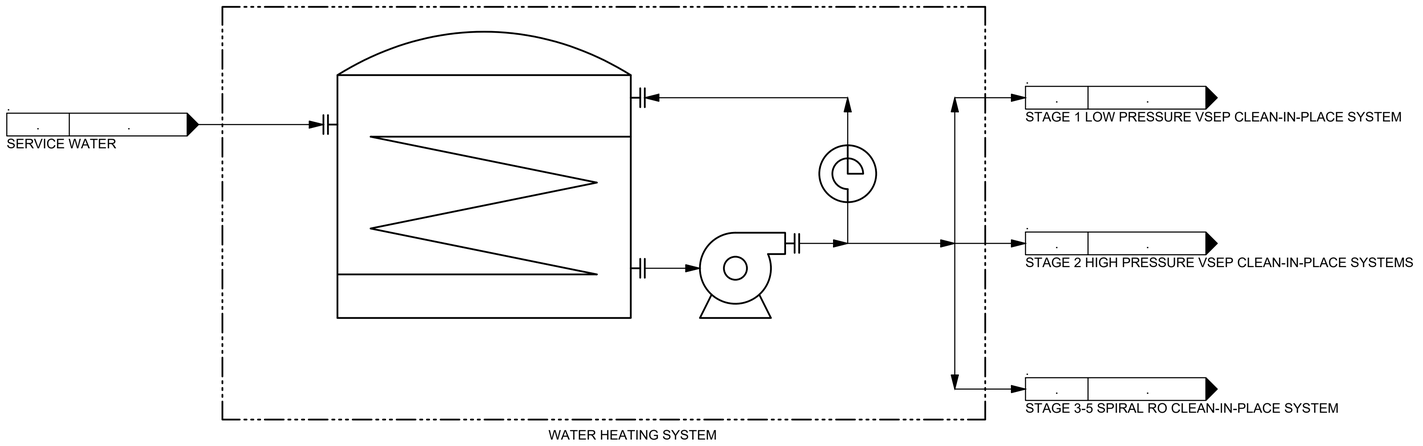
TITLE **PROCESS FLOW DIAGRAM**
AVARA EVAPORATION SYSTEMS

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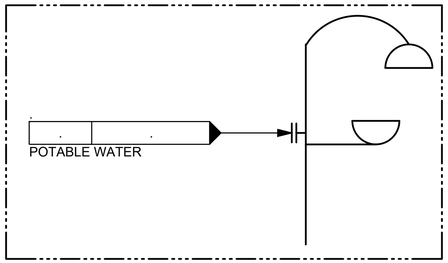
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Appellate Case: 24-2123 Page: 108 Date Filed: 07/26/2024 Entry ID: 5417837

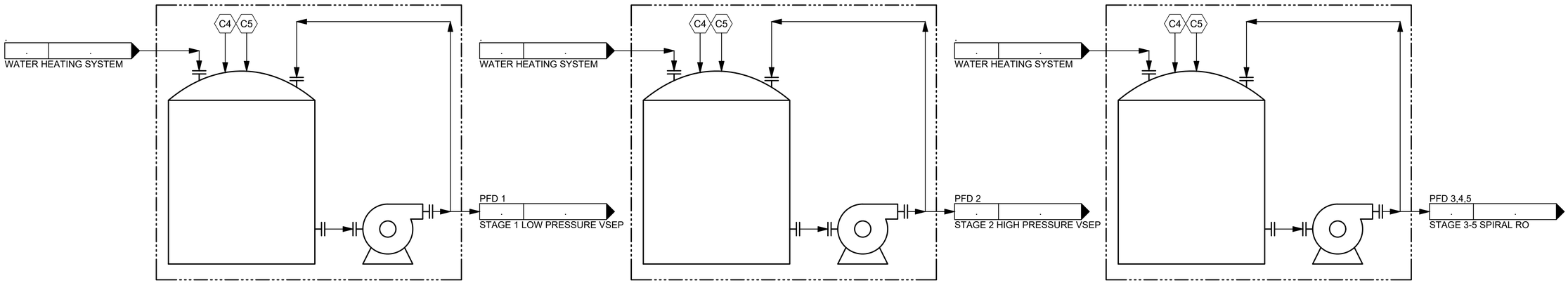
CHEMICAL LEGEND:
C1 - ACID
C2 - ANTISCALANT
C3 - BISULFITE
C4 - CIP LOW PH
C5 - CIP HIGH PH



WATER HEATING SYSTEM



SAFETY SHOWER AND
EYEWASH STATION



STAGE 1 LOW PRESSURE VSEP
CLEAN-IN-PLACE SYSTEM X 4

STAGE 2 HIGH PRESSURE VSEP
CLEAN-IN-PLACE SYSTEM X 2

STAGE 3-5 SPIRAL RO
CLEAN-IN-PLACE SYSTEM X 1

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ENGINEER:	WESTECH ENGINEERING, LLC
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----	SALT LAKE CITY, UTAH
JOB NUMBER:	24877

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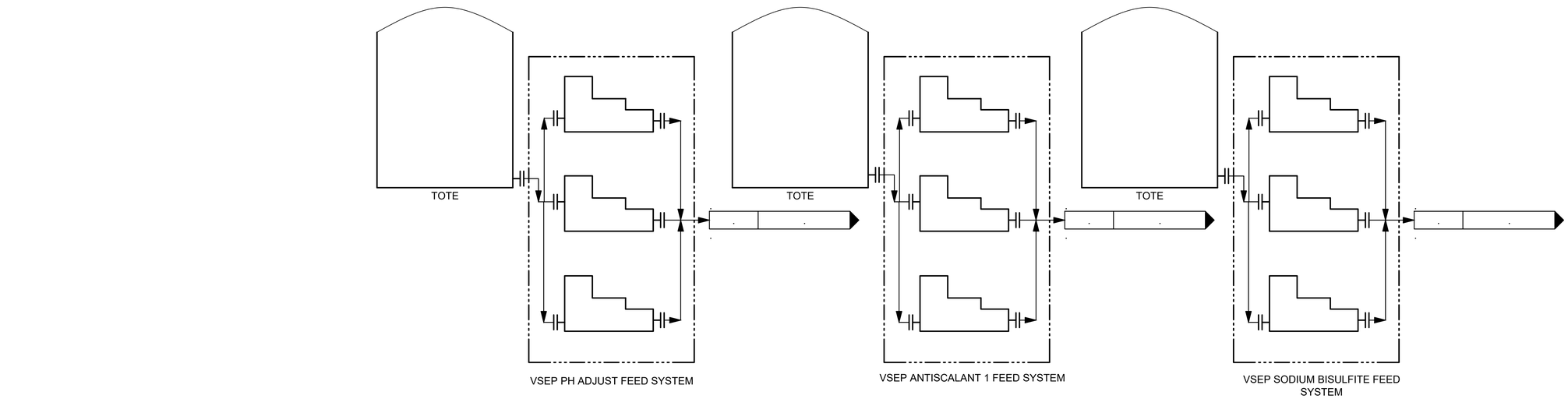
TITLE **PROCESS FLOW DIAGRAM**
CLEAN IN PLACE SYSTEMS

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24877A	**XXX**	7 OF 9	**A**

Appellate Case: 24-2133 Page: 109 Date Filed: 07/26/2024 Entry ID: 5417837

G:\ACTVJOBS\24800\JOBS\24877A PLANT MILLER VIP – ENGINEERING STUDY, AL\DRAWINGS\24877A_PLANT MILLER_1.0\PID DWG\24877A-PR-PFD-01



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---- QUINTON, ALABAMA
---- ----
ENGINEER: WESTECH ENGINEERING, LLC
---- SALT LAKE CITY
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CONTRACTOR: WESTECH ENGINEERING, LLC
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TITLE **PROCESS FLOW DIAGRAM**
CHEMICAL SYSTEMS

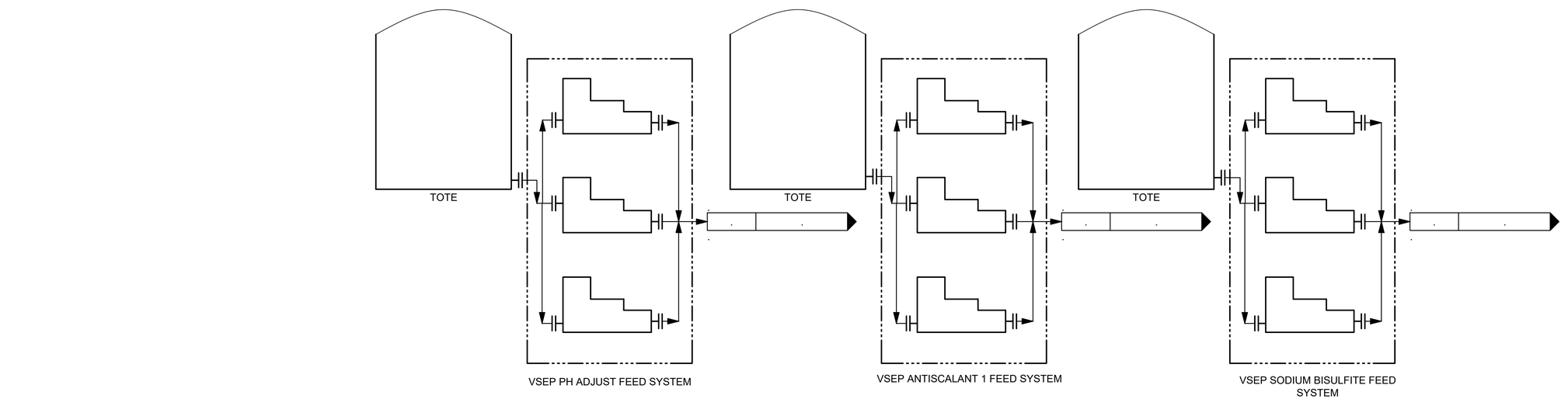
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24877A	**XXX**	8 OF 9	**A**

Appellate Case: 24-2113 Page: 110 Date Filed: 07/26/2024 Entry ID: 5417837

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PREPARED FOR PLANT MILLER
---- FGD WASTEWATER VSEP TREATMENT CONVERSION
---- QUINTON, ALABAMA
---- ----
ENGINEER: WESTECH ENGINEERING, LLC
---- SALT LAKE CITY
---- ----
CONTRACTOR: WESTECH ENGINEERING, LLC
---- SALT LAKE CITY, UTAH
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JOB NUMBER: 24877
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TITLE **PROCESS FLOW DIAGRAM**
CIP CHEMICAL SYSTEMS

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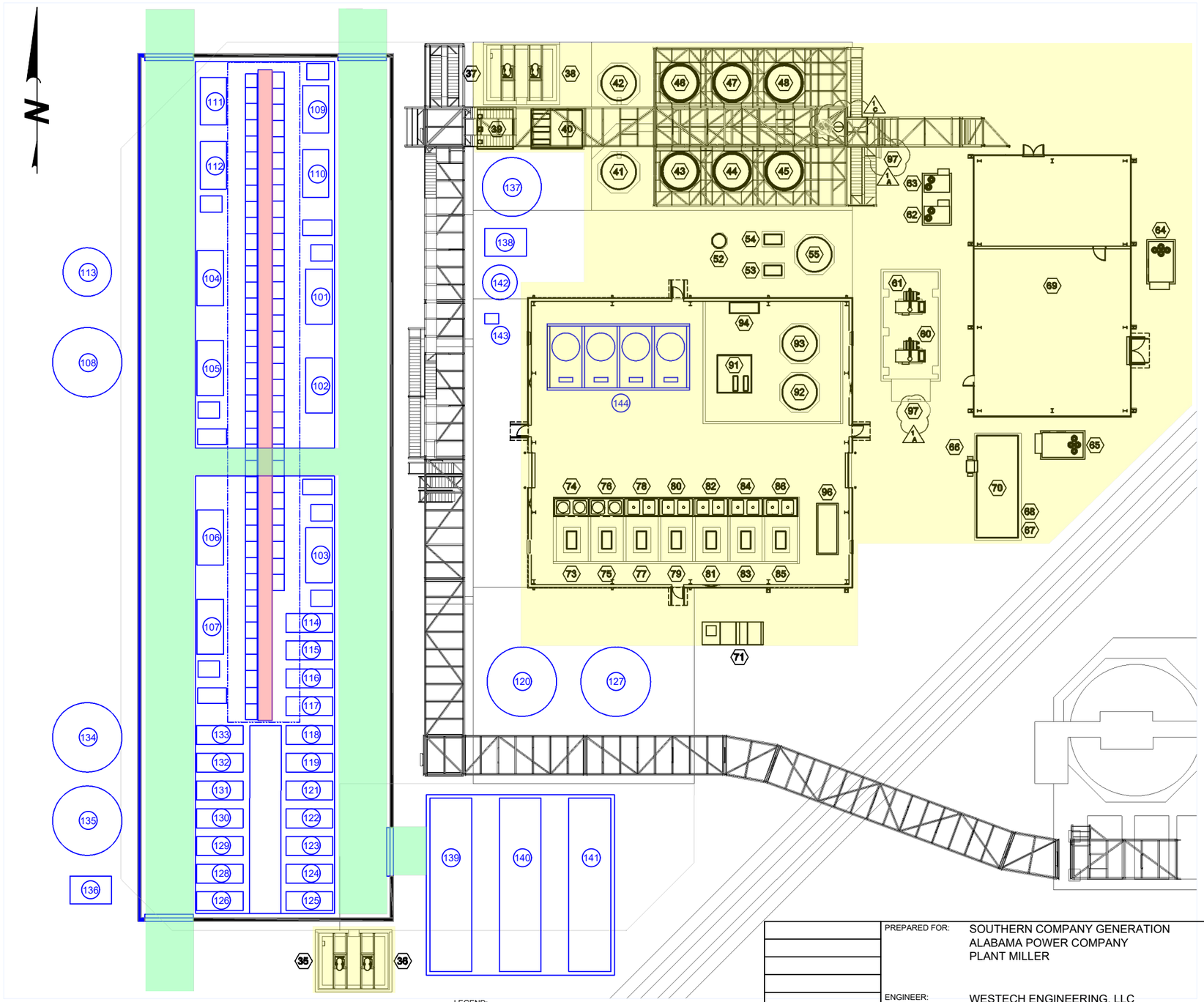
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24877A	**XXX**	9 OF 9	**A**

Appellate Case: 24-2113 Page: 111 Date Filed: 07/26/2024 Entry ID: 5417837

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Site Plan

Appellate Case: 24-2123 Page: 112 Date Filed: 07/26/2024 Entry ID: 5417837



NEW EQUIPMENT LIST	
ID NUMBER	DESCRIPTION
101	STAGE 1A VSEP
102	STAGE 1B VSEP
103	STAGE 1C VSEP
104	STAGE 1D VSEP
105	STAGE 1E VSEP
106	STAGE 1F VSEP
1077	STAGE 1G VSEP
108	STAGE 1 VSEP FEED TANK
109	STAGE 2A VSEP
110	STAGE 2B VSEP
111	STAGE 2C VSEP
112	STAGE 2D VSEP
113	STAGE 2 VSEP FEED TANK
114	STAGE 3A VSEP
115	STAGE 3B VSEP
116	STAGE 3C VSEP
117	STAGE 3D VSEP
118	STAGE 3E VSEP
119	STAGE 3F VSEP
120	STAGE 3 VSEP FEED TANK
121	STAGE 4A VSEP
122	STAGE 4B VSEP
123	STAGE 4C VSEP
124	STAGE 4D VSEP
125	STAGE 4E VSEP
126	STAGE 4F VSEP
127	STAGE 4 VSEP FEED TANK
128	STAGE 5A VSEP
129	STAGE 5B VSEP
130	STAGE 5C VSEP
131	STAGE 5D VSEP
132	STAGE 5E VSEP
133	STAGE 5G VSEP
134	STAGE 5 VSEP FEED TANK
135	PERMEATE FORWARDING STORAGE TANK
136	PERMEATE FORWARDING PUMP
137	CONCENTRATE STORAGE TANK
138	CONCENTRATE FORWARDING PUMP
139	AVARA SYSTEM A
140	AVARA SYSTEM B
141	AVARA SYSTEM C
142	HOT WATER TANK
143	HOT WATER FORWARDING PUMP
144	CHEMICAL SYSTEM AREA

REV	REVISION DESCRIPTION	ECN	DESIGNER	APPROVER	DATE
A	FOR INFORMATION ONLY	-	HA76	SO74	2023-02-01

REFERENCE DOCUMENTS

PREPARED FOR: SOUTHERN COMPANY GENERATION
ALABAMA POWER COMPANY
PLANT MILLER

ENGINEER: WESTECH ENGINEERING, LLC
SALT LAKE CITY, UTAH

CONTRACTOR:

PO/CONTRACT NUMBER 1179664

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TITLE **PLANT MILLER UNITS 1-4**
OVEALL SITE LAYOUT
PLAN VIEW

CLIENT DOCUMENT NUMBER

DESIGNER	CHECKER	APPROVER	DATE
HA76	BA123	SO74	2023-02-01

JOB NUMBER	DOCUMENT NUMBER	SHEET	REV
24877A		11 OF 11	1

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Process Description

Membrane Treatment System

Stage 1 VSEP Feed Tank

The influent for the system goes into the Stage 1 VSEP Feed Tank. The Stage 1 VSEP Feed Tank is fed by the existing Multimedia Filter effluent. The Tank also receives flow from the concentrate of the Stage 3 Reverse Osmosis (RO) membrane. Acid is added to the Stage 1 Tank for any necessary pH adjustment. Anti-scalant and bisulfite are dosed in the header to prevent scaling and reduce chlorine respectively.

The Stage 1 Low Pressure VSEPs pull from the Stage 1 VSEP Feed Tank. To prevent cavitation of the VSEP Feed Pumps, a Booster Pump on the feed line starts when both low pressure VSEP membranes are active.

Stage 1 Low Pressure VSEP

The Low Pressure VSEP Membranes use membrane filtration to separate suspended and dissolved solids. They employ a unique vibrating filter pack that produces a high shear rate on the membrane surface which inhibits membrane surface fouling and induces greater filtrate flow rates during the filtration process.

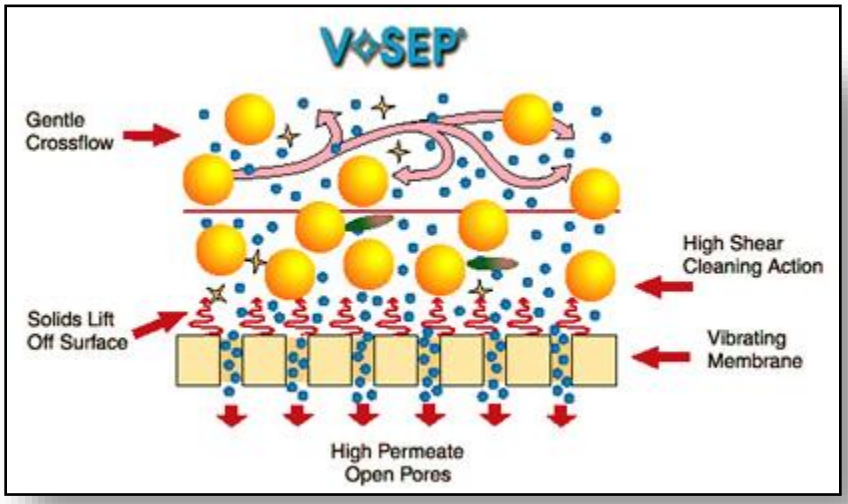


Figure 1. New Logic Vibratory Shear Enhanced Processing Membrane leaf element tangential vibration process. Courtesy of https://www.vsep.com/technology/

The Stage 1 Low Pressure VSEPs discharge two streams: permeate (filtrate or product) and concentrate (brine or retentate). The VSEP concentrate is sent to the Stage 2 High Pressure VSEP Feed Tank. The permeate is sent to the Stage 3 Spiral RO Feed Tank.

The membranes will need to be cleaned occasionally to remove accumulated foulants or scaling. There are two modes of cleaning, flush and CIP. Flush is a lower pressure single pass step where heated RO permeate is sent to the system for removal of foulants and/or scaling. CIP is a lower pressure recirculation step where heated RO permeate mixed with cleaning chemicals is sent to the system for removal of more stubborn foulants.

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Stage 2 High Pressure VSEP Feed Tank

The Stage 2 High Pressure VSEP Feed Tank receives flow from the Low Pressure VSEP membranes concentrate. This Tank is the feed tank to the Stage 2 High Pressure VSEP membranes for further volume reduction. Antiscalant is dosed after the Feed Tank to prevent scaling.

Stage 2 High Pressure VSEP

The High Pressure VSEP membranes use membrane filtration to separate suspended and dissolved solids. They employ a unique vibrating filter pack that produces a high shear rate on the membrane surface which inhibits membrane surface fouling and induces greater filtrate flow rates during the filtration process. Stage 2 membranes operate at a higher pressure than Stage 1 due to the higher dissolved solids loading in the brine feed that must be rejected at the membrane surfaces.

The Stage 2 High Pressure VSEPs discharge two streams: permeate (filtrate or product) and concentrate (brine or retentate). The Stage 2 High Pressure VSEP concentrate is sent to the Concentrate Storage Tank. The permeate is sent to the Stage 3 Spiral RO Feed Tank.

The membranes will need to be cleaned occasionally to remove accumulated foulants or scaling. There are two modes of cleaning, flush and CIP. Flush is a lower pressure single pass step where heated RO permeate is sent to the system for removal of foulants and/or scaling. CIP is a lower pressure recirculation step where heated RO permeate mixed with cleaning chemicals is sent to the system for removal of more stubborn foulants.

Stage 3 Spiral RO Feed Tank

The Stage 3 Spiral RO Feed Tank receives flow from the Stage 1 Low Pressure VSEP permeate, Stage 2 High Pressure VSEP permeate, and Stage 4 Spiral RO concentrate. This tank is the feed tank to the Stage 3 Spiral RO membranes for further polishing.

Stage 3 Spiral RO

The Stage 3 Spiral RO is the first stage of polishing after the VSEP membranes. There are 3 stages of RO (Stages 3, 4, and 5) total. The last stage is required to lower the mercury concentration to the required effluent quality. The same principles of operation apply to this membrane as the Stage 1 Low Pressure VSEP membranes. The feed stream is separated into 2 discharge streams: permeate and concentrate. The permeate is sent to the Stage 4 Spiral RO Feed Tank. The concentrate is recycled back to the Stage 1 Low Pressure VSEP Feed Tank for additional processing. The Stage 3 Spiral RO is cleaned in a similar manner to the Stage 1 and 2 VSEP membranes.

Stage 4 Spiral RO Feed Tank

The Stage 4 Spiral RO Feed Tank receives flow from the Stage 3 Spiral RO permeate, and Stage 5 Spiral RO concentrate. This tank is the feed tank to the Stage 4 Spiral RO membranes.

Stage 4 Spiral RO

The Stage 4 Spiral RO is the second stage of polishing after the VSEP membranes. The same principles of operation apply to this membrane as the Stage 3 Spiral RO membranes. The feed stream is separated into 2 discharge streams: permeate and concentrate. The permeate is sent to the Stage 5 Spiral RO Feed Tank. The concentrate is recycled back to the Stage 3 Spiral RO Feed Tank for additional processing. The Stage 4 Spiral RO is cleaned in a similar manner to the previous system membranes.

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Stage 5 Spiral RO Feed Tank

The Stage 5 Spiral RO Feed Tank receives flow from the Stage 4 Spiral RO permeate. This tank is the feed tank to the Stage 5 Spiral RO membranes.

Stage 5 Spiral RO

The Stage 5 Spiral RO is the third and final stage of polishing after the VSEP membranes. The same principles of operation apply to this membrane as the previous spiral RO membranes. The feed stream is separated into 2 discharge streams: permeate and concentrate. The permeate is sent to the Permeate Forwarding Storage Tank. This permeate water will meet the effluent limits assumed from the 2020 ELG VIP. The concentrate is recycled back to the Stage 4 Spiral RO Feed Tank for additional processing. The Stage 5 Spiral RO is cleaned in a similar manner to the previous system membranes.

Permeate Forwarding Storage Tank

The Permeate Forwarding Storage Tank will receive flow from the Stage 5 Spiral RO membranes and the AVARA distillate. The Permeate Forwarding Storage Tank supplies the Permeate Forwarding Pump Skid that sends water to the FGD Effluent Tank located in the existing Phys/Chem Treatment Area. Contents of the FGD Effluent Tank are pumped to the river for final discharge.

Concentrate Storage Tank

The Concentrate Storage Tank will receive the concentrate flow from the Stage 2 High Pressure VSEP membranes. It will feed the AVARA system.

Thermal Evaporator (AVARA)

There will be 3 Thermal Evaporators in parallel in this process. The thermal evaporators will be AVARA systems. AVARAs use advanced vapor recompression technology for thermal evaporation and to concentrate a brine stream. AVARA systems are fully automated and come as a fully skidded solution.

The Thermal Evaporators will operate as 3x33%. The AVARAs will be fed by the Concentrate Storage Tank. The brine of the 3 AVARAs will go to the Brine Storage Tank while the distillate will be fed to the permeate forwarding tank.

The Thermal Evaporator is used to concentrate brine from the High Pressure VSEP membranes to the point just before saturation. It is expected that the concentration of TDS could reach up to 262,000 ppm.

The Thermal Evaporators will heat the feed concentrate to the point of boiling. Water is pumped through a 500-mesh self-cleaning filter and split into two streams. One stream is sent through the distilled heat-exchanger while the other is sent through the brine heat exchanger. The streams recombine and are sent to the core tank section of the AVARA.

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Figure 2. AVARA Advanced Vapor Recompression Process Schematic – Heat Exchange. Courtesy of www.purestream.com/project-2

In the core tank section, water is boiled to create a saturated vapor. Vapor is compressed to between 3 and 7.5 PSI with a blower. The compressed vapor is then forced through dimpled plates. As the vapor moves through the plates, it condenses. The condensed and distilled water is then pumped through the feed heat exchangers and out of the system as effluent to the Permeate Forwarding Storage Tank.

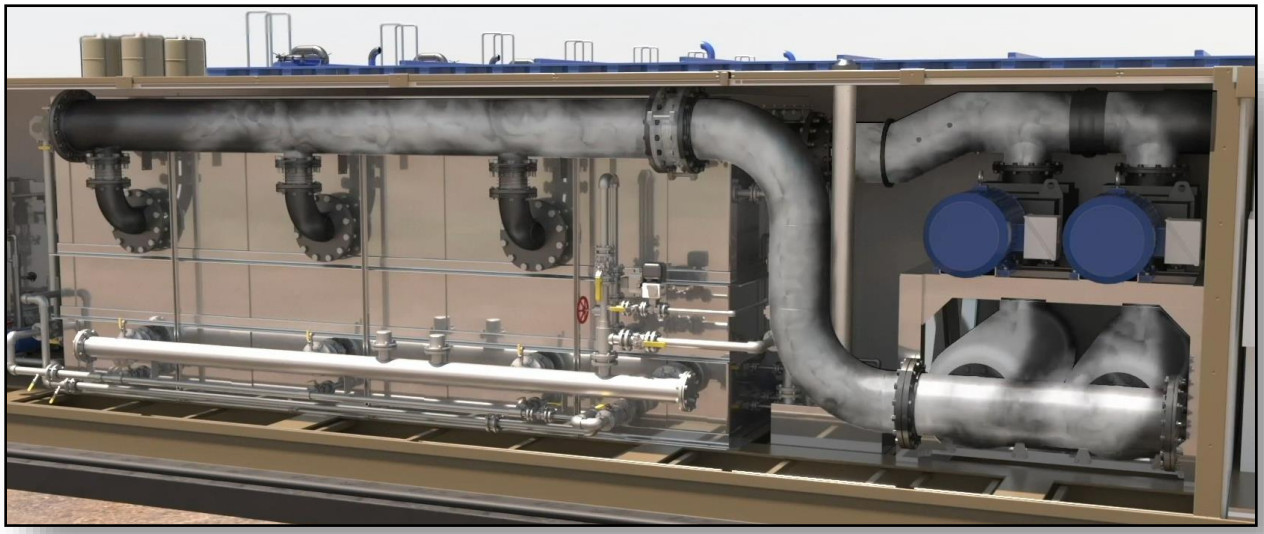


Figure 3. AVARA Advanced Vapor Recompression Process Schematic – Vaporization. Courtesy of www.purestream.com/project-2

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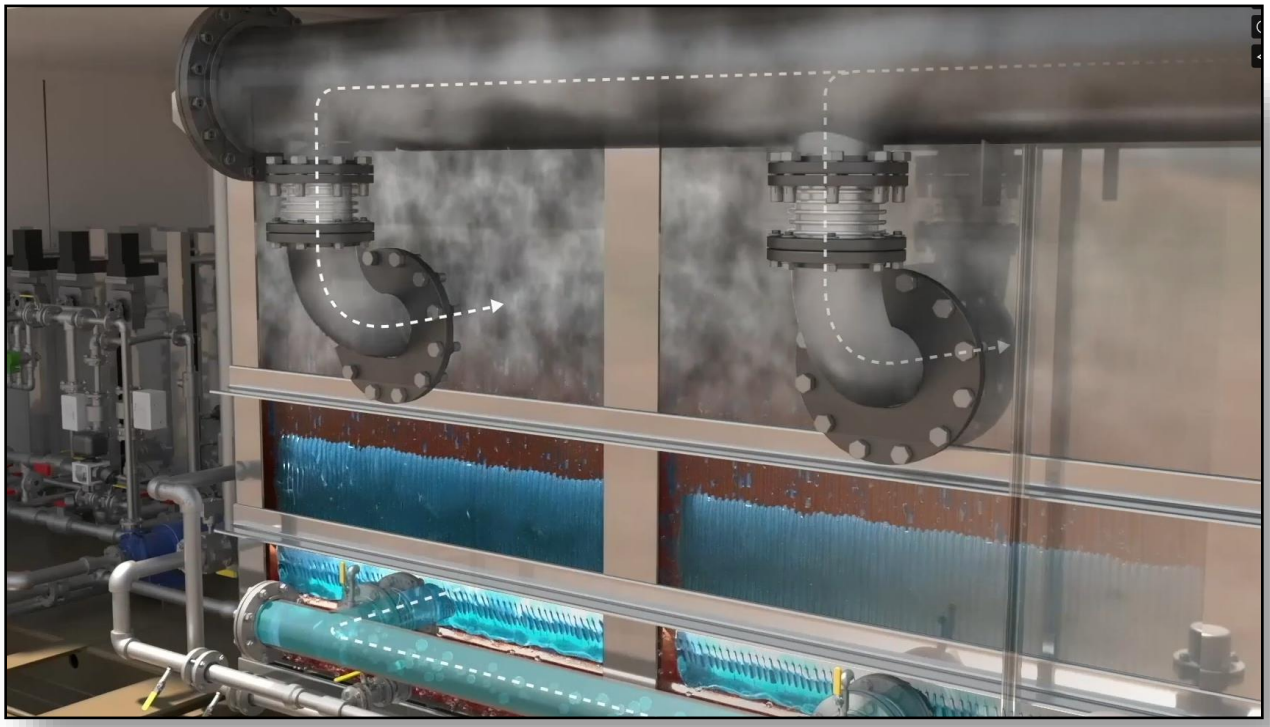


Figure 4. AVARA Advanced Vapor Recompression Process Schematic – Condensation. Courtesy of www.purestream.com/project-2

Operators watch the pressures within the AVARA. Changes in pressure can change production rate and temperature making it a key process condition. Operators can adjust relief valves, heater temperature, blower speed, and the heat exchanger by-pass valve to optimize system pressures.

With much of the feed water evaporated, condensed, and discharged, the brine left in the AVARA will continue to recirculate through the heat exchanger. Once it is concentrated to near saturation, it is pumped out of the system. A control valve will control brine discharge flowrate and will be set to maintain the desired brine concentration. Brine will be sent to the Brine Storage tank and then processed through the Solidification Batch Plant.

Brine Solidification Batch Plant

The solidification plant will collect, store, and meter dry solidification materials and brine for loading into a cement mixer. These solidification materials are Flyash, Lime, and standard concrete conditioning additives. Flyash with small amounts of lime will be used as the primary solidification material. If Flyash is not readily available Cement and lime can be used as an alternative. These materials will be stored in silos above a weigh hopper. These materials will be metered into the weigh hopper at a known quantity. This hopper will feed the dry material into cement trucks followed by brine for mixing. The solidification plant will be designed for fugitive dust control. The cement truck will transport the mixed material for disposal. The solidified brine mixture will pass both the paint filter test and the Toxicity Leaching Characteristic Procedure prior to being landfilled in an off-site facility.

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Equipment List

Table 8. Plant Miller Budgetary Study Major Equipment List

Major Equipment List			
Item	**Description**	**Materials**	**Size**
Influent Pump Skid	Centrifugal	SS	1 Skid 2 x 100% pumps per skid @ 20 psi 610 gpm total 10 HP each
Stage 1 VSEP Feed Tank	Flat Bottom Tank (Knock Down) No Roof	FRP	1 x 100% 50,000 gal 20'D x 25'H
Stage 1A – 1G VSEP Feed & Booster Pumps	Vertical Multi-Stage Centrifugal	SS	7 Skids 4 x 25% pumps per skid @ 450 PSI 608 gpm total 200 HP each
Stage 1A – 1G Low Pressure VSEP Membranes	Vibrating disc membrane filters	Varies	7 Skids 8 Modules per Skid 54 of 56 Modules (84") (2 spare/future) 792 gpm total 8 x 20 HP Vibration Motors ~5650 lb
Stage 2 High Pressure VSEP Feed Tank	Cylindrical closed top tank	HDPE	1 x 100% 12,000 gal 12'D x 16' – 7.75"H
Stage 2A – 2D High Pressure VSEP Feed Pumps	Positive displacement	SS	4 skids 4 x 25% pumps per skid @ 750 PSI 200 gpm total 30 HP each
Stage 2A – 2D Membranes High Pressure VSEP Membranes	Vibrating disc membrane filters	Varies	4 Skids 4 Modules per Skid 16 of 16 Modules (17") (0 spare/future) 200 gpm total 6 x 20 HP Vibration Motors ~5650 lb

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Item	Description	Materials	Size
Stage 3 Spiral RO Feed Tank	Flat Bottom Tank (Knock Down) No Roof	FRP	1 x 100% 50,000 gal 20'D x 25'H
Stage 3A – 3F Spiral RO Feed & Booster Pumps	Vertical Multi-Stage Centrifugal	SS	On Spiral RO Skid (6x) 2 pumps per skid @ 300 PSI 840 gpm total 100 HP each
Stage 3A – 3F Spiral RO Membranes	S-18000 Spiral System Spiral-wound membrane filters Pre-Screen Basket Strainers Included	Varies	6 Skids 45 Elements per skid (270 Total) (0 spare/future) 840 gpm total ~12,000lb
Stage 4 Spiral RO Feed Tank	Flat Bottom Tank (Knock Down) No Roof	FRP	1 x 100% 45,000 gal 20'D x 22' – 6"H
Stage 4A – 4F Spiral RO Feed & Booster Pumps	Vertical Multi-Stage Centrifugal	SS	On Spiral RO Skid (6x) 2 pumps per skid @ 200 PSI 745 gpm total 60 HP each
Stage 4A – 4F Spiral RO Membranes	S-18000 Spiral System Spiral-wound membrane filters Pre-Screen Basket Strainers Included	Varies	6 Skids 45 Elements per skid (270 Total) (0 spare/future) 745 gpm total ~12,000 lb
Stage 5 Spiral RO Feed Tank	Steel Bottom Tank (Knock Down) A36 Construction, No Roof	FRP	1 x 100% 35,000 gal 20'D x 18' – 6"H
Stage 5A – 5F Spiral RO Feed & Booster Pumps	Vertical Multi-Stage Centrifugal	SS	On Spiral RO Skid (6x) 2 pumps per skid @ 200 PSI 610 gpm total, 50 HP each

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Item	Description	Materials	Size
Stage 5A – 5F Spiral RO Membranes	S-18000 Spiral System Spiral-wound membrane filters Pre-Screen Basket Strainers Included	Varies	6 Skids 45 Elements per skid (270 Total) (0 spare/future) 610 gpm total ~12,000 lb
Permeate Forwarding Storage Tank	Steel Bottom Tank (Knock Down) A36 Construction, No Roof	FRP	1 x 100% 30,000 gal 20'D x 18' – 6"H
Permeate Forwarding Pumps	Vertical Multi-Stage Centrifugal	SS	2 x 100% @ 60 PSI 610 gpm 15 HP
Concentrate Storage Tank	Flat Bottom Tank (Knock Down)	FRP Tank	1 x 100% 30,000 gal 17'D x 28'H Θ = 5.3 hr @ max flow Θ = 16 hr @ 1 AVARA off-line
	Includes Top Mounted Mixer and Mixer Bridge (supports to grade)	Carbon steel for mixer bridge (Painted)	7.5HP mixer
Evaporator Feed Pump	Horizontal Centrifugal	SS	3 x 33% @ 60PSI 90 gpm total, 30 gpm each 1.5 HP each
Evaporator Booster Pumps	Horizontal Centrifugal	SS	6 x 33% @ 43PSI 90 gpm total, 30 gpm each 5 HP each

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Item	Description	Materials	Size
Evaporators	AVARA Advanced Vapor Recompression System	Varies	3 x 33% 90 gpm total, 30 gpm each 12'W x 50'L x 10'H each 20.5 GPM Brine Flow *Power Requirements:* 480V/3 Ph/ 600 Amp Breaker x (6) 3600 Amp Total MVR Vapor Blowers A/B: 200 HP Core Heaters 6 x 40 kW
Distillate Discharge Pump(s)	Horizontal Centrifugal	SS	3 x 33% *25 gpm @ 45 psi, 5 HP* (68.54 gpm total)
Concentrate (Brine) Recycle/Discharge Pump(s)	Horizontal Centrifugal	SS	3 x 33% *10 gpm @ 60 psi, 5 HP* (23.1 gpm total)
Stage 1 Low Pressure VSEP Clean-in-Place System	Vertical Multi-Stage Centrifugal Pump	316 SS Pump	QTY – 4 Systems 1 x 100% pumps each @ 250 PSI 60 gpm 20HP
	pH Sensor Level Sensor	HDPE Tank/Piping	260-gal HDPE Tank 3'D x 6' – 4"H ~2010 lb each
Stage 2 High Pressure VSEP Clean-in-Place Systems	Vertical Multi-Stage Centrifugal Pump	316 SS Pump	QTY – 2 Systems 1 x 100% pumps each @ 250 PSI 60 gpm 20HP
	pH Sensor Level Sensor	HDPE Tank/Piping	200-gal HDPE Tank each 3'Dx 4' – 6"H ~2010 lb each

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Item	Description	Materials	Size
Stage 3-5 Spiral RO Clean-in-Place System	Vertical Multi-Stage Centrifugal Pump	316 SS Pump	QTY – 1 Systems 1 x 100% pumps each @ 185 PSI 60 gpm 20HP
	pH Sensor Level Sensor	HDPE Tank/Piping	200-gal HDPE Tank each 3'D x 4'– 6"H ~2010 lb each
Water Heating System		Varies	400 HP max Tank – 6,100 gal 10'D x 12' – 8"H
Brine Storage Tank(s)	Closed Top Cylindrical Tank with Mixing	HDPE 316 SS Wetted Mixer End*	3 x 33% 20.5 gpm 24 hours of storage 12,000 gal ea.

*Mixer material selection may change depending on the results of future pilot results.

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Table 9. Chemical Feed Systems and Tankage Equipment List

Chemical Feed Systems & Tankage			
Item	**Description**	**Materials**	**Size**
VSEP Antiscalant 1 Feed System	Tote Fed 100% Active	HDPE Skid, Sch 80 PVC Plumbing	2 x 100% Metering pumps (plus shelf spare) 1 gph 0.5 HP each
VSEP pH Adjust Feed System	Tote Fed Sulfuric Acid 93% Active	HDPE Skid, Sch 80 PVC Plumbing	2 x 100% Metering pumps (plus shelf spare) 1.2 gph 0.5 HP each
VSEP Sodium Bisulfite Feed System	Tote Fed 40% Active	HDPE Skid, Sch 80 PVC Plumbing	2 x 100% Metering pumps (plus shelf spare) 2 gph 0.5 HP each
VSEP Antiscalant 2 System	Tote Fed 100% Active	HDPE Skid, Sch 80 PVC Plumbing	2 x 100% Metering pumps (plus shelf spare) 1 gph 0.5 HP each
Spiral RO Antiscalant 2 System	Tote Fed	HDPE Skid, Sch 80 PVC Plumbing	2 x 100% Metering pumps (plus shelf spare) 1 gph 0.5 HP each
Stage 1 Low Pressure VSEP Low pH Membrane Cleaner (NLR 404) Feed System	See NLR 404 Storage Tank	Varies	4 x 100% Metering pumps 1 HP each
Stage 1 Low Pressure VSEP CIP High pH Membrane Cleaner (NLR 505) Feed System	See NLR 505 Storage Tank	Varies	4 x 100% Metering pumps 1 HP each
Stage 2 High Pressure VSEP CIP Low pH Membrane Cleaner (NLR 404) Feed System	See NLR 404 Storage Tank	Varies	2 x 100% Metering pumps 1 HP each
Stage 2 High Pressure VSEP CIP High pH Membrane Cleaner (NLR 505) Feed System	See NLR 505 Storage Tank	Varies	2 x 100% Metering pumps 1 HP each
Stage 3-5 Spiral RO CIP Low pH Membrane Cleaner (NLR 404) Feed System	See NLR 404 Storage Tank	Varies	1 x 100% Metering pumps 1 HP each

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Item	Description	Materials	Size
Stage 3-5 Spiral RO CIP High pH Membrane Cleaner (NLR 505) Feed System	See NLR 505 Storage Tank	Varies	1 x 100% Metering pumps 1 HP each
NLR 404 Storage Tank	Cylindrical Closed Top Chemical Storage Tank	HDPE	1 x 100% 4000 gal
NLR 505 Storage Tank	Cylindrical Closed Top Chemical Storage Tank	HDPE	1 x 100% 4000 gal
AVARA Acid Feed System	Tote Fed		2 x 100% Metering pumps (plus shelf spare) 1 gph 1 HP each
AVARA Antiscalant Feed System	Tote Fed		2 x 100% Metering pumps (plus shelf spare) pumps 1 gph 0.5 HP each

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Level 1 Schedule

[Attached separately until final draft]

Major Equipment Lead Times

Table 10. Major Equipment Lead Times

Major Equipment Lead Times	
Equipment (Vendor)	**Lead Time**
Membranes (New Logic Research)	24 months
Evaporators (Purestream - AVARA)	10 months
Solidification Batch Plant (Jamieson)	30 weeks

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VSEP & AVARA Equipment Descriptions

Item A – VSEP Membranes and Spiral RO Membrane Systems

Table 11. New Logic VSEP and Spiral RO Membrane System Design Overview

System Design Overview	
Parameter	**Value**
Influent Flow Rate	608 gpm
Estimated Average Filtrate Rate Performance[1]	16 gfd
Estimated System Filtrate Recovery	85%
Design Basis[2]	25°C, 450 psi – LP VSEP, 750 psi HP VSEP
Stage 1 LP VSEP Recovery	~75%
Stage 1 LP VSEP Design Flux	16 gfd
Stage 2 HP VSEP Recovery	~55%
Stage 2 HP VSEP Design Flux	12 gfd
Stage 3 SRO Recovery	~78%
Stage 4 SRO Recovery	~82%
Stage 5 SRO Recovery	~85%
Stage 3 – 5 SRO SRO Design Flux	10 gfd

1. Estimated average performance at 10,000 mg/L TDS.
2. See Basis of Design and Equipment List for Stage specific pressure requirements

Design Assumptions:

Design Case 1:

The VSEP Stage 1 modules are designed for a total flow rate of 792 gpm. This includes 608 gpm of phys/chem effluent at a TDS concentration of 10,000 mg/L and 184 gpm of recycled reject from the Stage 3 Spiral RO Membranes. A membrane efficiency factor of 130% is applied to the design flux to reflect the decrease in membrane throughput over time. The operating flux is expected to decline to 100% of the design flux after three years of operation.

Membrane cleaning frequency is estimated on a per day basis at roughly 8% of an operational day. It is important to note that this is not the actual cleaning/maintenance frequency and is an estimated average value.

The third stage of the spiral RO is required due to the high influent mercury levels of 10,000 to 15,000 ng/L. The Second Stage Spiral RO can achieve approximately 30 ng/L, and the additional third stage is needed to achieve the required effluent value of 10 ng/L.

Design Case 2:

Design Case 2 assumes a majority of phys/chem effluent is recycled back to the FGD scrubbers as makeup water. The remaining water is sent to the membrane treatment system (150 gpm, 35,000 pm

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TDS, 15,000 ng/L Hg, total). This flow may be routed directly to the Stage 2 HP VSEP membranes for treatment and achieve identical effluent values with Design Case 1 feeding the Stage 1 LP VESP membranes. Stage 2 HP VSEP permeate is sent through the Spiral RO Membrane stages with reject from those stages recycled back to the Stage 2 HP VSEP influent.

VSEP Stage 1 Low Pressure Membranes Specifications:

Filter Pack:

Membrane:	RO
Allowable Process Temperature:	5°C - 60°C
Allowable Feed Slurry pH Range:	2 - 12
O-ring and Seal Material:	EPDM
Filter Pack Housing:	Glass impregnated epoxy resin (FRP)
Wetted Steel Trays:	304 Stainless Steel
Wetted Plastic End Plates:	Polypropylene

Vibration System:

Vibration Drive Motor:	Baldor CM4106T 460VAC, 3phase, 20HP, 3525 RPM
Motor Speed Controller:	Danfoss 380-480 VAC NEMA 4 (or equal)
Max. Vibration Amplitude:	3/4 inch (peak to peak measured at the Filter Pack)
Frequency Range:	49.0 Hz to 55.0 Hz (Approximate)
Maximum Decibels:	<85
Bearing RPM:	2800 to 3100
Bearing Oil:	Sullube ~750 ml Compressor Oil
Bearing O-rings:	2-263 & 2-270 Buna

Pump Specifications:

Feed Pump Type:	Grundfos 316SS Vertical Multi-stage Centrifugal
Feed Pump Motor:	Grundfos ML 3500 rpm TEFC 460VAC, 3phase
Motor Speed Controller:	Danfoss 380-480 VAC NEMA 4 (or equal)
Chemical Metering Pump:	Bran+Luebbe MD 200S 19111 007
Metering Pump Motor:	Baldor 3/4HP TEFC 120/220V, 1phase, 15A, 60/50Hz

Pre-Screen Basket Strainer:

Filter Housing Type:	NLR Custom Made Alloy 2507
Basket Strainer:	60 Mesh 316 SS (Considered consumable)
Capacity:	220 GPM (50m3/hr)
Elastomers (Seals):	EPDM

Operating Site Conditions:

Equipment Rating:	NEMA 4, Indoor/Outdoor protect from sunlight & rain.
Ambient Temperature:	5° - 37°C
Storage Temperature:	2° - 70°C (Protect Filter Pack from Freezing)
Max Relative Humidity:	<95%, non-condensing
Elevation:	3300 ft maximum without derating VFD

Piping:

Maximum Pressure:	550 psi (3,800 kPa)

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Feed/Concentrate Pressure Piping:	Schedule 80 Super Duplex 2507
Permeate Piping:	Schedule 40 316 SS
Special VSEP Concentrate Pipe:	1-1/4” OD Alloy 20 Stainless Steel .065 wall
Flexible Hoses:	Neoprene Lined Reinforced Flex Hose
Pipe Clamps:	Victaulic Zero-Flex Style 07 EPDM
Pneumatic Air Supply:	90lb Instrument Grade Air (3/8" connection)
Airline Tubing Fittings:	Hylok 316 SS
Piping Drain Fittings:	Hylok 2507 Duplex
Feed/Conc On/Off Valves:	Flotite Alloy 2507 3-piece ball valve
Permeate On/Off Valves:	Flotite 316 SS 3-piece ball valve
Flow Control Valves:	Flotite Alloy 2507 V-port ball valve
Permeate Check Valves:	316 SS Swing check
Pneumatic Actuators:	Habonim Compact, Spring Return
Feed/Concentrate Pipe Terminations:	150 lb Alloy 2507 Flange
Permeate Pipe Terminations:	150 lb 316 SS Flange
Flange Gaskets:	150 lb Garlock Blue Guard

Clean in Place (CIP):

CIP Pump Type:	Grundfos 316 SS Vertical Multi-Stage Centrifugal
CIP Pump Motor:	Grundfos ML 3500 rpm TEFC 460 VAC 3-phase
Motor Speed Controller:	Danfoss 380-480 VAC NEMA 4 (or equal)
Clean in Place Tank:	260 Gallon Cross Linked Polypropylene
pH Meter:	GF Signet 3-2726-00, 3-2750-1, 3-9900-1
Level Sensor:	IFM Efector PN-2298

Electrical Specifications:

Controls Voltage:	220/120VAC, 1phase, 15A, 50/60Hz
Enclosures:	Hoffman NEMA 4 Powdercoat Finish 48x30x10, 24x30x8
Switches, Relays, & Contactors:	Allen Bradley 220/110 Volt
Programmable Controller:	AB ControlLogix 1769
Operator Display:	AB Versa View 5400
IO Link Masters and Hubs:	IFM Efector AL1122
Feed/Conc Pressure Sensors:	IFM Efector PN-2292 (with 2507ss seals)
Permeate Pressure Sensors:	IFM Efector PN-2292 316ss
Conc Mag Flow Tube and Transmitter:	Rosemount (or equal) (with Hastelloy electrodes/flanges)
Perm Mag Flow Tube and Transmitter:	IFM Efector SM2000 316ss
Bag Filter DP Sensors:	Efector PN-2294 (with 2507ss seals)
Temperature Sensor:	IFM Efector TN-2511, (with 2507ss thermowell)
Conductivity Meter:	Rosemount or equal (PEEK, Hastelloy, EPDM)
pH Meter:	Rosemount or equal (PEEK, glass, Hastelloy, EPDM)
Solenoid Valve:	Festo Manifold Gang Mounted Dual 3/2 24 VDC, IO Link
CIP Communication:	IFM Efector IO Link Masters over Ethernet
VFD Communication:	Ethernet Com Card (Ethernet Switch)
DCS Communication	Ethernet OPC Server (option for Modbus)

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VSEP Stage 2 High Pressure Membranes Specifications:

Filter Pack:

Membrane:	RO
Allowable Process Temperature:	5° - 60°C
Max Process Pressure:	1000 psi (7000 kPa)
Allowable Feed Slurry pH Range:	2 - 12
O-ring and Seal Material:	EPDM (option for Viton)
Filter Pack Housing:	Glass impregnated epoxy resin (FRP)
Wetted Steel Trays:	316 Stainless Steel
Wetted Plastic End Plates:	Polypropylene

Vibration System:

Vibration Drive Motor:	Baldor 380-480VAC, 3phase, 20HP, 3525 RPM Motor
Speed Controller:	Danfoss 20HP 380-480VAC, NEMA 4 (or Equal) Max.
Vibration Amplitude:	3/4 inch (peak to peak measured at the Filter Pack)
Frequency Range:	43.0 Hz to 55.0 Hz (Approximate)
Maximum Decibels:	<85
Bearing RPM:	2800 to 3100
Bearing Oil:	Sullube ~750 ml Compressor Oil
Bearing O-rings:	2-263 & 2-270 Buna

Pump Specifications:

Feed Pump Type:	Hydracell Hastelloy, Horizontal Teflon Diaphragm
Feed Pump Motor:	Baldor 380-480VAC, 3phase, 30HP, 1200 RPM
Booster Transfer Pump Type:	NOTE Supplied by Customer at Feed Tank (24 ft NPSH)
Motor Speed Controller:	Danfoss 380-480VAC, NEMA 4 (or Equal)
Chemical Metering Pump:	Bran+Luebbe Diaphragm pump with manual stroke
Metering Pump Motor:	Baldor 3/4HP TEFC 120/220V, 1phase, 15A, 60/50Hz
Dosing Solenoid Pump:	Chemtech Series 100

Pre-Screen Basket Strainer:

Filter Housing Type:	NLR Custom Made 2507 Alloy Shell
Basket Strainer:	100 Mesh 316 SS (Considered Consumable)
Capacity:	120 GPM, 4.6 sq ft
Elastomer Seals:	EPDM (option for Viton)

Operating Site Conditions:

Equipment Rating:	NEMA 4, Indoor/Outdoor protect from sunlight & rain.
Ambient Temperature:	5° - 37°C
Storage Temperature:	2° - 70°C (Protect Filter Pack from Freezing)
Max Relative Humidity:	<95%, non-condensing
Elevation:	3300 ft maximum without derating VFD

Piping:

Maximum Pressure:	900 psi
Feed/Concentrate Pressure Piping:	Schedule 80 Super Duplex 2507

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Permeate Piping:	Schedule 40 316 SS
Special VSEP Concentrate Pipe:	1-1/4” OD Alloy 20 Stainless Steel .065 wall
Flexible Hoses:	Neoprene Lined Reinforced Weatherhead Flex Hose
Pipe Clamps:	Victaulic Zero-Flex Style 07 EPDM
Pneumatic Air Supply:	90lb Instrument Grade Air (3/8" connection)
Airline Tubing Fittings	Hylok 316 SS
Piping Drain Fittings	Hylok 2507 Duplex
Feed/Conc On/Off Valves	Flotite Alloy 2507 3-piece ball valve
Permeate On/Off Valves	Flotite 316 SS 3-piece ball valve
Flow Control Valves	Flotite Alloy 2507 V-port ball valve
Permeate Check Valves	316 SS Swing check
Pneumatic Actuators	Habonim Compact, Spring Return
Feed/Concentrate Pipe Terminations	150 lb Alloy 2507 Flange
Permeate Pipe Terminations	150 lb 316 SS Flange
Flange Gaskets	150 lb Garlock Blue Guard
Flange Gaskets:	150 lb Garlock Blue Guard

CIP:

CIP Pump Type:	Grundfos 316SS Vertical Multi-stage Centrifugal
CIP Pump Motor:	Grundfos ML 3500 rpm TEFC 460VAC, 3phase
Motor Speed Controller:	AC Tech 380-480VAC, NEMA 4 (or Equal)
Clean in Place Tank:	200 Gallon Sloped Cross Linked Polypropylene
pH Meter:	GF Signet 3-2726-00, 3-2750-1, 3-9900-1
Level Sensors:	IFM Efector PN-2298

Electrical:

Controls Voltage:	120/220VAC, 1phase, 15A, 50/60Hz
Enclosures:	Hoffman NEMA 4 Powdercoat Finish
Wireway Gutters:	Hoffman NEMA 4 Powdercoat Finish
Switches, Relays, & Contactors:	Allen Bradley 120/220 Volt
Remote Access:	Ewon Cosy 131
Programmable Controller:	AB Compact Logix 1769
Operator Display:	AB Versa View 5400
IO Link Masters and Hubs:	IFM Efector AL1122
Feed/Conc Pressure Sensors	IFM Efector PN-2292 (with 2507ss seals)
Permeate Pressure Sensors	IFM Efector PN-2292 316ss
Conc Mag Flow Tube and Transmitter	Rosemount (or equal) (with Hastelloy electrodes/flanges)
Perm Mag Flow Tube and Transmitter	IFM Efector SM2000 316ss
Bag Filter DP Sensors	Efector PN-2294 (with 2507ss seals)
Temperature Sensor	IFM Efector TN-2511, (with 2507ss thermowell)
Conductivity Meter	Rosemount or equal (PEEK, Hastelloy, EPDM)
pH Meter	Rosemount or equal (PEEK, glass, Hastelloy, EPDM)
Solenoid Valves:	Festo Manifold Gang Mounted Dual 3/2 24 VDC, IO Link
CIP Communication:	IFM Efector IO Link Masters over Ethernet
VFD Communication:	Ethernet Com Card (Ethernet Switch)
DCS Communication:	Ethernet OPC Server (option for Modbus)

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Spiral RO Stages 3 – 5 Membranes (S-18000) Specifications

Filter Pack:

Membrane:	RO (depends on application and pilot testing)
Membrane Surface Area:	18000sf (1672m2) (45ea 8”Dia x 40”L)
Maximum Operating Temperature:	120˚F (49˚C) (Options for up to 80˚C)
Allowable Feed Slurry pH Range:	2 - 11
O-ring Material:	Ethylene Propylene
Filter Pack Housing:	Polyurethane Coated, Filament Wound, Epoxy
FRP Wetted Ports:	316L Stainless Steel
Wetted Plastic End Plates:	PVC Thermoplastic

Piping:

Maximum Pressure:	550 psi (Options for up to 1200
psi) Pressure Piping:	316L Stainless Steel Schedule 80
Atmospheric Piping:	316L Stainless Steel Schedule 40
Pipe Clamps:	Zero-Flex Victaulic Style 07
EPDM On/Off Valves:	316 SS 3-piece ball valve
Flow Control Valves:	316 SS V-port ball valve
Check Valves:	316 SS swing check valve
Pneumatic Actuators:	Habonim Compact, Spring Return
Positioners:	BLX Linear Quarter Turn I/P
Skid Pipe Terminations:	150 lb 316 SS Raised Face Flange
Flange Gaskets:	150 lb Garlock Blue Guard

Pump Specifications:

Feed Pump Type:	Grundfos 316SS Vertical Multi-stage
Centrifugal Feed Pump Motor:	Grundfos ML 3500 rpm TEFC 460VAC, 3phase
Motor Speed Controller:	Danfoss 380-480VAC, NEMA 4 (or Equal)

Pre-Screen Basket Strainer:

Filter Housing Type:	NLR Custom Made 316 SS
Basket Strainer:	100 Mesh 316SS (Optional Felt Bag Filter)
Capacity:	120 GPM, 4.6 sq ft
Elastomer Seals:	EPDM (option for Viton)

Operating Site Conditions:

Equipment Rating:	NEMA 4, Indoor/Outdoor protect from sun & rain.
Ambient Temperature:	5 - 37°C
Storage Temperature:	2 - 70°C (Project Filter Pack from Freezing)
Max Relative Humidity:	<95%, non-condensing
Elevation:	3300 ft maximum without derating

Electrical Specifications:

The membrane (VSEP) system is typically provided with a PLC/HMI control panel which also controls the spiral RO system. This control panel is mounted on the Clean in Place (CIP) Skid that is also shared for both membrane types.

Controls Voltage:	120/220VAC, 1phase, 15A,5 0/60Hz

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Programmable Controller Type:	None (Control signals from CIP PLC)
Touch Screen Display Type:	None (Set Point change at CIP HMI)
Enclosures:	*Hoffman* NEMA 4 Powdercoat Finish 20x16x8
Switches, Relays, & Contactors:	Allen Bradley 120/220 Volt
IO Link Masters and Hubs:	IFM Efector AL1122
Pressure Sensors:	IFM Efector PN-2292
Mag Flow Tube and Transmitter:	IFM Efector SM2000, SM8000
Bag Filter DP Sensors:	IFM Efector PN-2294
Temperature Sensor:	IFM Efector TN-2511, UT0028
Conductivity Meter:	IFM Efector LDL-100
Solenoid Valves:	Festo Manifold Gang Mounted Dual 3/2 24 VDC, IO Link
VSEP and CIP Communication:	IO Link
VFD Communication:	Ethernet Com Card
DCS Communication:	Ethernet OPC Server (option for Modbus)

Item B – AVARA: Advanced Vapor Recompression System

Table 12. Advanced Vapor Recompression System (AVARA) System Design Overview

System Design Overview	
Parameter	**Value**
Total Influent Flow Rate	89 gpm
Total Estimated Evaporation	65.9 gpm
Total Estimated Brine	23.1 gpm
Feed TDS	68,211 ppm
Target Brine TDS	262,000 ppm
Nominal Operating Electricity	4,140 kW
Required Electricity	480V / 3 Phase / 4140 Service Amps

AVARA features patented submerged core technology. Feed water is pumped into a tank and heated with immersion heaters. As steam is generated, compressors force the steam back into the submerged heat exchanger (core) where the steam recondenses into a clean distillate. The AVARA is capable of concentrating the residual brine in the tank up to 300,000 ppm TDS before being discharged from the system for disposal or beneficial use. AVARA can significantly reduce the amount of wastewater requiring disposal while providing a distilled water byproduct.

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AVARA Specifications

Table 13. AVARA System Design Specifications (per Treatment Unit)

AVARA System Specifications (per Treatment Unit)	
Parameter	**Value**
Skid Dimension	12’ W x 50’ L x 10’ H
Skid Shipping Weight	100,000 lbs
Weather Enclosed	Yes
Fuel Type	Electricity: Grid or Genset
Line Power	3 Phase – 480V; 800 Service Amps; 500 Running Amps
Generated Power	Min. 450kW Genset (prime rated)
Volume Capacities	Mid-range to high TDS feed
Discharge TDS	Up to 300,000+ PPM TDS
Inlet Water Pressure	5’ Head Pressure
Set-up Time	24 Hours
Remote Monitoring	Yes

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Maintenance Requirements

Table 14. AVARA Operations and Maintenance Requirements Summary

AVARA O&M Requirements

AVARA Unit	Total Feed Flow (gpm)*	Energy Usage (kW)	Service Amps	Energy Costs**	Estimated Maintenance & Replacement Costs	Chemical Cleaner	Total System Cost
Unit 1	29.7	565	1380	$9.70	$4.60	$4.00	$18.30
Unit 2	29.7	565	1380	$9.70	$4.60	$4.00	$18.30
Unit 3	29.7	565	1380	$9.70	$4.60	$4.00	$18.30
Totals	89	1695	4140	$29.10	$13.80	$12.00	$54.90

*Includes all recycling flows
**Energy Costs assumed at $0.10/kW-hr. Operational Day assumed at 22hrs/day.
***Costs given as $/1000gal of feed to equipment item

Table 15. Membrane Operations and Maintenance Requirements Summary

Membrane O&M Requirements

Stage	Total Feed Flow (gpm)*	Estimated Time between Cleanings	Energy Consumption / Usage	Energy Costs**	Estimated Membrane Life/Module Replacement Cost / Cost	Chemical Cleaner Usage (gal per day)/ Cost	Total System Cost
Stage 1 LP VSEP Membranes	791.6	2880 min	677 hp / 505 kW	$0.97	3 yr / $84,000 ea. / $3.63	54 / $0.85	$5.45
Stage 2 HP VSEP Membranes	198.0	2000 min	230 hp / 172 kW	$1.32	2 yr / $90,000 ea. / $6.92	23 / $1.45	$9.69
Stage 3 Spiral RO Membranes	836.6	50000 min	172 hp / 129 kW	$0.23	5 yr / $1,400 ea. / $0.23	20 / $0.27	$0.73
Stage 4 Spiral RO Membranes	744.6	50000 min	102 hp / 76 kW	$0.16	5 yr / $1,400 ea. / $0.24	10 / $0.14	$0.54
Stage 5 Spiral RO Membranes	610.6	50000 min	84 hp / 62 kW	$0.16	5 yr / $1,400 ea. / $0.25	8 / $0.15	$0.56
Totals	-	-	-	$2.84	$11.27	$2.86	$16.97

*Includes all recycling flows
**Energy Costs assumed at $0.10/kW-hr. Operational Day assumed at 22hrs/day.
***Costs given as $/1000gal of feed to equipment item

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O&M Labor

It is assumed that the AVARA systems will require 24 hours per day for managing all three units simultaneously. This would require one (1) person managing the three units 24-7 on a per shift basis. The VSEP membranes are estimated to require one (1) full time employee for treatment and maintenance operations on a 24-7 basis. An additional three (3) employees would be required for maintenance of the entire treatment system on a 20 hour per week basis.

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Solidification Equipment Descriptions

Item A – Standley Batch Systems, Inc.

Table 16. Encapsulation Standley Batch Systems Fly Ash Silo Overview

Item No.	Description
1A	Flyash Silo (1850 cuft)
1B	Flyash Silo (1850 cuft)
2A	Flyash Silo (1850 cuft)
2B	Flyash Silo (1850 cuft)
3A	Flyash Silo (1850 cuft)
3B	Flyash Silo (1850 cuft)
3C	Lime Silo (1600 cuft)
4	HyControl Silo Safety (7 Silo)
5	Screw Conveyors (2)
6	Weigh Batcher
7	Water Tank and Weigh Batcher
8	Drive Thru Structure
9	Collecting Hopper
10	Valve Bank Enclosure
11	Starter Enclosure

Item B – C&W DusTech

Table 17. C&W DusTech System Overview

Item No.	Description
12	Dust Collector w/ Explosion Protection
13	Flap Valve Package
14	Drive Up Truck Dust Shroud
15	Ductwork Package (Shroud)
16	Ductwork Package (Silos)
17	Weigh Batcher Dust Collector
18	Mounting Flange-Weigh Batcher

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Item C – Command Alkon

Table 18. Command Alkon System Overview

Item No.	Description
19	Freight
20	Water Scale
21	Command Batch CP Control
22	Continuous Bin Levels
23	Installation
24	Travel
25	Project Management
26	Airfare
27	Expenses

Item D – BinMaster Inventory Management

Table 19. BinMaster Inventory Management Overview

Item No.	Description
28	Continuous Measurement System (7 silo)
29	Mounting Plates (7)
30	Bin Disc Interface
31	Data Cable
32	On-site Startup

Item E – Solidification Site Work and Installation

Table 20. Solidification Site Work and Installation Services Overview

Item No.	Description
33	Foundations, Ramps, Dust Collector Pads, Piers, Curbs
34	Installation and Erection

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Engineering & Design Services

Scope of Services

Deliverables developed during the engineering and design phase will serve as the basis of design for the project. The following engineering tasks and deliverables are included in this bid:

- Design Criteria
- Process Flow Diagram
- Process & Instrumentation Diagrams
- Mass Balance
- Hydraulic Profile
- Equipment Descriptions (GA drawings & Datasheets)
- Control Narrative
- Equipment Layout
- 3D Plant Modeling
- Site Civil Design
- HVAC Design
- Design & Construction Schedule

Process Flow Diagram (PFD)

WesTech offers a wide range of treatment equipment that can be implemented in multiple process configurations and we will refine the approach with input from the finalized Design Criteria.

The PFD will identify the major pieces of equipment, their position in the process and the main control loops operating the process. They will indicate the main process streams and utility lines.

Deliverable:

- Process Flow Diagram

Process & Instrumentation Diagrams (P&IDs)

After the Process Flow Diagram is finalized, WesTech will develop preliminary P&IDs for the process. The P&IDs will portray the components needed to run, monitor, control specific processes and will depict their relationship with each other. P&IDs will show equipment, piping that connects the equipment, instrumentation, and valves. The information compiled in the P&ID will provide the blueprint for the system and set the scope of the final project, define the process parameters and the level of controls. The P&IDs and supporting documentation are the most important document when establishing the details of the project.

P&IDs will be generated following ISA S5.1 and the owner's specifications. P&IDs typically include, but are not limited to the following information:

- Equipment names, tag and design conditions
- Relief valve location, tag numbers, sizes and pressure. Relief valve interlocks

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- Venting, draining, maintenance, shutdown and start-up requirements are indicated
- Type of manual valves are identified, specialty piping items are tagged, and piping notes are added
- Control valves size, fail position, tags, and interlocks
- Vessel nozzles, details, and levels
- Process and utility lines
- Line sizes, line numbers, pipe specifications and product designation are indicated
- All instrumentation is shown with alarm and switch set points
- Instrument signals to control system are detailed
- Scope of supply, system boundaries

Deliverable:

- P&IDs based on finalized PFD

Mass Balance

WesTech will perform mass balance calculations based on the finalized Design Criteria and PFD. Mass balance values will be used as inputs for specific equipment sizing.

Deliverable:

- Mass Balance calculations based on finalized PFD

Equipment Descriptions (General Arrangement Drawings & Datasheets)

WesTech will provide detailed equipment descriptions including General Arrangement (GA) drawings, equipment datasheets, and other lists as required.

Deliverables:

- Equipment datasheets
- GA drawings

Hydraulic Profile

WesTech will perform hydraulic calculations for the treatment system within the specified boundaries given in the Battery Limits Table of the Design Basis.

Deliverables:

- Hydraulic profile drawing

HAZOP Assistance

WesTech will provide personnel for one (1) trip up to five (5) working days to participate in a hazard and operability study (HAZOP) workshop that will be conducted by others. Our process and controls engineers will assist in identifying and evaluating potential risks to personnel or equipment and operability issues.

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Control Narrative

WesTech process engineers will provide control narratives in paragraph form describing functionality of each unit process. Descriptions will include an overall description of the piece of equipment and how it is operated via pumps, blowers, valves, instruments, control logic, etc. Descriptions will also outline interactions between individual unit processes. The control narrative will provide the basis for PLC logic programming.

Equipment Layout

As the equipment manufacturer, WesTech is intimately familiar with the plant site layout requirements needed to produce a functional site plan. Our in-house former mechanical piping contractors are experts at laying out piping networks to connect all the plant components. We use 3D modeling software to further increase our accuracy with interconnecting piping and civil structures.

Deliverable:

- Equipment layout drawings in native AutoCAD

3D Plant Modeling

- Equipment and interconnecting piping model
- Provided in native AutoCAD Plant 3D
- Periodic updates viewable in NavisWorks

Deliverables:

- 50% Model Review Workshop
- 90% Model Review Workshop

Site Civil Design

- Site survey & topography
- Geotechnical investigation
- Finish grading plan design
- Storm drainage design
- Access road design
- Footing and foundation design

HVAC Design

- Area classification identifications
- Heat load calculations
- Ventilation fan and louver sizing
- Unit heater equipment selection, and location drawings
- Make-up air unit sizing and ducting design drawings

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- Mechanical cooling unit equipment selection and location drawings

Design & Construction Schedule

WesTech will develop a detailed design and construction schedule that will be used by the team to ensure resources are properly allocated and to identify critical path items. The schedule will be a detailed Gantt chart using the latest Primavera P6 software to outline design, construction and start-up milestones.

Deliverable:

- Initial detailed design & construction Gantt chart schedule

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Commercial Proposal

Proposal Name: Plant Miller Budgetary Study
Proposal Number: 24877
Tuesday, February 07, 2023

1. Bidder's Contact Information

Company Name	WesTech Engineering LLC
Primary Contact Name	Dallas Torgersen
Phone	801.265.1000
Email	DTorgersen@westech-inc.com
Address: Number/Street	3665 S West Temple
Address: City, State, Zip	Salt Lake City, UT 84115

2. Budget Pricing

Currency: US Dollars

Scope of Supply

A	Engineering	$13,000,000.00
B	Procurement (Includes MCC and PDC Building)	$71,660,000.00
C	Freight	$710,000.00
D	Construction	$56,500,000.00
E	Commissioning & Start-up	$5,860,000.00
F	Solidification:	
F.1	Solidification Equipment	$3,853,647.00
F.2	Solidification Site Work and Installation	$1,503,045.00
Process Island Cost		$153,086,692.00
	Taxes (sales, use, VAT, IVA, IGV, duties, import fees, etc.)	Not Included

Prices are valid for a period not to exceed 30 days from date of proposal.

3. Additional Field Service

Daily Rate (Applicable Only to Field Service Not Included in Scope)	$1,450

Pricing does not include field service unless noted in scope of supply, but is available at the daily rate plus expenses. The greater of a two week notice or visa procurement time is required prior to departure date. Our field service policy can be provided upon request for more details.

4. Schedule

Please refer to Level 1 Schedule Section

5. Freight

Domestic		FOB Shipping Point - Prepaid and Added (FSP-PPA)
From	**Final Destination**	**Number of Trucks or Containers**
WesTech Shops	Quinton, AL	Approximately TBD

The Process Island Cost provided includes only the costs associated with WesTech's discrete scope of work, as outlined in this budgetary study. A "Total Project Cost" estimate (including but not limited to such costs as decommissioning of Plant Miller's biological treatment system, project management, insurance, etc.) will likely be generated by Alabama Power Company and/or Southern Company Services and would represent the comprehensive dollar figure associated with the installation of the new treatment system at Plant Miller.

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Clarifications and Exceptions

This report is provided as a non-binding budgetary study. The scope included does not reflect WesTech's intended scope of work if this project were to be actualized.

General Clarifications

Terms & Conditions: Changes to any terms and conditions, including but not limited to submittal and shipment days, payment terms, and escalation clause shall be negotiated at order placement, otherwise the proposal terms and conditions contained herein shall apply.

Paint: If your equipment has paint included in the price, please take note to the following. Primer paints are designed to provide only a minimal protection from the time of application (usually for a period not to exceed 30 days). Therefore, it is imperative that the finish coat be applied within 30 days of shipment on all shop primed surfaces. Without the protection of the final coatings, primer degradation may occur after this period, which in turn may require renewed surface preparation and coating. If it is impractical or impossible to coat primed surfaces within the suggested time frame, WesTech strongly recommends the supply of bare metal, with surface preparation and coating performed in the field. All field surface preparation, field paint, touch-up, and repair to shop painted surfaces are not by WesTech.

Escalation: If between the proposal date and actual procurement and through no fault of the Seller, the relevant cost of labor, material, freight, tariffs, and other Seller costs combined relating to the contract, increase by greater than 2.5% of the overall contract price, then the contract price shall be subject to escalation and increased. Such increase shall be verified by documentation and the amount of contract price escalation shall be calculated as either the actual increased cost to the Seller or, if agreed by the Parties, the equivalent increase of a relevant industry recognized third-party index, and in both cases without any additional profit or margin being added.

USA Tariffs and Current Trade Laws: All prices are based on current USA and North America tariffs and trade laws/agreements at time of bid. Any changes in costs due to USA Tariffs and trade laws/ agreements will be passed through to the purchaser at cost.

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One-Year Warranty

WesTech is meeting a global need for clean water through technology treatment solutions. We are proud that the equipment and systems we design, build, maintain, and operate are making the world a better place and creating a more sustainable environment for future generations.

Equipment manufactured or sold by WesTech Engineering, LLC, once paid for in full, is backed by the following warranty:

Subject to the terms below, WesTech warrants all new equipment manufactured or sold by WesTech Engineering, LLC to be unencumbered and free from defects in material and workmanship, and WesTech will replace or repair, F.O.B. its factories or other location it chooses, any part or parts returned to WesTech which WesTech's examination and analysis determine have failed within the warranty period because of defects in material and workmanship. The warranty period is either, one calendar year immediately following start-up, or eighteen (18) months from when WesTech sent its ready-to-ship notification to the purchaser, whichever expires sooner. All repair or replacement parts qualifying under this warranty shall be free of charge. Purchaser will provide timely written notice to WesTech of any defects it believes should be repaired or replaced under this warranty. WesTech will reject as untimely any warranty defect claim that purchaser submits more than thirty (30) days after the possible warranty defect first occurred. Unless specifically stated otherwise, this warranty does not cover normal wear or consumables. This warranty is not transferable.
This warranty shall be void and shall not apply where the equipment or any part thereof.

(a) has been dismantled, modified, repaired or connected to other equipment, outside of a WesTech factory, or without WesTech's written approval, or
(b) has not been installed in complete adherence to all WesTech's or parts manufacturer's requirements, recommendations, and procedures, or
(c) has been subject to misuse, abuse, neglect, or accident, or has not at all times been operated and maintained in strict compliance with all of WesTech's requirements and recommendations therefor, including, but not limited to, the relevant WesTech Operations & Maintenance Manual and any other of WesTech's specified guidelines & procedures, or
(d) has been subject to force majeure events; use of chemicals not approved in writing by WesTech; electrical surges; overloading; significant power, water or feed supply fluctuations; or non-compliance with agreed feedwater or chemical volumes, specifications or procedures.

In any case where a part or component of equipment under this warranty is or may be faulty and the component or part is also covered under the warranty of a third party then the purchaser shall provide reasonable assistance to first pursue a claim under the third-party warranty before making a claim under this warranty from WesTech. WesTech Engineering, LLC gives no warranty with respect to parts, accessories, or components purchased other than through WesTech. The warranties which apply to such items are those offered by the respective manufacturers.

This warranty is expressly given by WesTech and accepted by purchaser in lieu of all other warranties whether written, oral, express, implied, statutory or otherwise, including without limitation, warranties of merchantability and fitness for particular purpose. WesTech neither accepts nor authorizes any other person to assume for it any other liability with respect to its equipment. WesTech shall not be liable for

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normal wear and tear, corrosion, or any contingent, incidental, or consequential damage or expense due to partial or complete inoperability of its equipment for any reason whatsoever. The purchaser's exclusive and only remedy for breach of this warranty shall be the repair and or replacement of the defective part or parts within a reasonable time of WesTech's accepting the validity of a warranty claim made by the purchaser.

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Terms & Conditions

Terms and Conditions appearing in any order based on this proposal which are inconsistent herewith shall not be binding on WesTech Engineering LLC The sale and purchase of equipment described herein shall be governed exclusively by the foregoing proposal and the following provisions:

1. SPECIFICATIONS: WesTech Engineering LLC is furnishing its standard equipment as outlined in the proposal and as will be covered by final approved drawings. The equipment may not be in strict compliance with the Engineer's/Owner's plans, specifications, or addenda as there may be deviations. The equipment will, however, meet the general intention of the mechanical specifications of these documents.

2. ITEMS INCLUDED: This proposal includes only the equipment specified herein and does not include erection, installation, accessories, nor associated materials such as controls, piping, etc., unless specifically listed.

3. PARTIES TO CONTRACT: WesTech Engineering LLC is not a party to or bound by the terms of any contract between WesTech Engineering LLC's customer and any other party. WesTech Engineering LLC's undertakings are limited to those defined in the contract between WesTech Engineering LLC and its direct customers.

4. PRICE AND DELIVERY: All selling prices quoted are subject to change without notice after 30 days from the date of this proposal unless specified otherwise. Unless otherwise stated, all prices are F.O.B. WesTech Engineering LLC or its supplier's shipping points. All claims for damage, delay or shortage arising from such equipment shall be made by Purchaser directly against the carrier. When shipments are quoted F.O.B. job site or other designation, Purchaser shall inspect the equipment shipped, notifying WesTech Engineering LLC of any damage or shortage within forty-eight hours of receipt, and failure to so notify WesTech Engineering LLC shall constitute acceptance by Purchaser, relieving WesTech Engineering LLC of any liability for shipping damages or shortages.

5. PAYMENTS: All invoices are net 30 days. Delinquencies are subject to a 1.5 percent service charge per month or the maximum permitted by law, whichever is less on all past due accounts. Pro rata payments are due as shipments are made. If shipments are delayed by the Purchaser, invoices shall be sent on the date when WesTech Engineering LLC is prepared to make shipment and payment shall become due under standard invoicing terms. If the work to be performed hereunder is delayed by the Purchaser, payments shall be based on the purchase price and percentage of completion. Products held for the Purchaser shall be at the risk and expense of the Purchaser. Unless specifically stated otherwise, prices quoted are for equipment only. These terms are independent of and not contingent upon the time and manner in which the Purchaser receives payment from the owner.

6. PAYMENT TERMS: Credit is subject to acceptance by WesTech Engineering LLC's Credit Department. If the financial condition of the Purchaser at any time is such as to give WesTech Engineering LLC, in its judgment, doubt concerning the Purchaser's ability to pay, WesTech Engineering LLC may require full or partial payment in advance or may suspend any further deliveries or continuance of the work to be performed by the WesTech Engineering LLC until such payment has been received.

7. ESCALATION: If shipment is, for any reason, deferred by the Purchaser beyond the normal shipment date, or if material price increases are greater than 5% from proposal date to material procurement date, stated prices set forth herein are subject to escalation. The escalation shall be based upon increases in labor and material and other costs to WesTech Engineering LLC that occur in the time period between quotation and shipment by WesTech Engineering LLC Purchaser agrees to this potential escalation regardless of contradicting terms in the contract, except when an agreed upon escalation adder is included in the price.

(a) The total quoted revised price is based upon changes in the indices published by the United States Department of Labor, Bureau of Labor Statistics. Labor will be related to the Average Hourly Earnings indices found in the Employment and Earnings publication. Material will be related to the Metal and Metal Products Indices published in Wholesale Prices and Prices Indices.

(b) Price revision for items furnished to, and not manufactured by WesTech Engineering LLC, which exceed the above escalation calculation, will be passed along by WesTech Engineering LLC to Purchaser based upon the actual increase in price to WesTech Engineering LLC for the period from the date of quotation to the date of shipment by WesTech Engineering LLC Any item that is so revised will be excluded from the index escalation calculations set forth in subparagraph (a) above.

8. APPROVAL: If approval of equipment submittals by Purchaser or others is required, a condition precedent to WesTech Engineering LLC supplying any equipment shall be such complete approval.

9. INSTALLATION SUPERVISION: Prices quoted for equipment do not include installation supervision. WesTech Engineering LLC recommends and will, upon request, make available, at WesTech Engineering LLC's then current rate, an experienced installation supervisor to act as the Purchaser's employee and agent to supervise installation of the equipment. Purchaser shall at its sole expense furnish all necessary labor equipment, and materials needed for installation.

Responsibility for proper operation of equipment, if not installed by WesTech Engineering LLC or installed in accordance with WesTech Engineering LLC's instructions, and inspected and accepted in writing by WesTech Engineering LLC, rests entirely with Purchaser; and any work performed by WesTech Engineering LLC personnel in making adjustment or changes must be paid for at WesTech Engineering LLC's then current per diem rates plus living and traveling expenses.

WesTech Engineering LLC will supply the safety devices described in this proposal or shown in WesTech Engineering LLC's drawings furnished as part of this order but excepting these, WesTech Engineering LLC shall not be required to supply or install any safety devices whether required by law or otherwise. The Purchaser hereby agrees to indemnify and hold harmless WesTech Engineering LLC from any claims or losses arising due to alleged or

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actual insufficiency or inadequacy of the safety devices offered or supplied hereunder, whether specified by WesTech Engineering LLC or Purchaser, and from any damage resulting from the use of the equipment supplied hereunder.

10. ACCEPTANCE OF PRODUCTS: Products will be deemed accepted without any claim by Purchaser unless written notice of non-acceptance is received by WesTech Engineering LLC within 30 days of delivery if shipped F.O.B. point of shipment, or 48 hours of delivery if shipped F.O.B. point of destination. Such written notice shall not be considered received by WesTech Engineering LLC unless it is accompanied by all freight bills for said shipment, with Purchaser's notations as to damages, shortages and conditions of equipment, containers, and seals. Non-accepted products are subject to the return policy stated below.

11. TAXES: Any federal, state, or local sales, use or other taxes applicable to this transaction, unless specifically included in the price, shall be for Purchaser's account.

12. TITLE: The equipment specified herein, and any replacements or substitutes therefore shall, regardless of the manner in which affixed to or used in connection with realty, remain the sole and personal property of WesTech Engineering LLC until the full purchase price has been paid. Purchaser agrees to do all things necessary to protect and maintain WesTech Engineering LLC's title and interest in and to such equipment; and upon Purchaser's default, WesTech Engineering LLC may retain as liquidated damages any and all partial payments made and shall be free to enter the premises where such equipment is located and remove the same as its property without prejudice to any further claims on account of damages or loss which WesTech Engineering LLC may suffer from any cause.

13. INSURANCE: From date of shipment until the invoice is paid in full, Purchaser agrees to provide and maintain at its expense, but for WesTech Engineering LLC's benefit, adequate insurance including, but not limited to, builders risk insurance on the equipment against any loss of any nature whatsoever.

14. SHIPMENTS: Any shipment of delivery dates recited represent WesTech Engineering LLC's best estimate but no liability, direct or indirect, is assumed by WesTech Engineering LLC for failure to ship or deliver on such dates.

WesTech Engineering LLC shall have the right to make partial shipments; and invoices covering the same shall be due and payable by Purchaser in accordance with the payment terms thereof. If Purchaser defaults in any payment when due hereunder, WesTech Engineering LLC may, without incurring any liability therefore to Purchaser or Purchaser's customers, declare all payments immediately due and payable with maximum legal interest thereon from due date of said payment, and at its option, stop all further work and shipments until all past due payments have been made, and/or require that any further deliveries be paid for prior to shipment.

If Purchaser requests postponements of shipments, the purchase price shall be due and payable upon notice from WesTech Engineering LLC that the equipment is ready for shipment; and thereafter any storage or other charge WesTech Engineering LLC incurs on account of the equipment shall be for the Purchaser's account.

If delivery is specified at a point other than WesTech Engineering LLC or its supplier's shipping points, and delivery is postponed or prevented by strike, accident, embargo, or other cause beyond WesTech Engineering LLC's reasonable control and occurring at a location other than WesTech Engineering LLC or its supplier's shipping points, WesTech Engineering LLC assumes no liability in delivery delay. If Purchaser refuses such delivery, WesTech Engineering LLC may store the equipment at Purchaser's expense. For all purposes of this agreement such tender of delivery or storage shall constitute delivery.

15. WARRANTY: WESTECH ENGINEERING LLC WARRANTS EQUIPMENT IT SUPPLIES ONLY IN ACCORDANCE WITH THE WARRANTY EXPRESSED IN THE ATTACHED COPY OF "WESTECH WARRANTY" AGAINST DEFECTS IN WORKMANSHIP AND MATERIALS WHICH IS MADE A PART HEREOF. SUCH WARRANTY IN LIEU OF ALL OTHER WARRANTIES, INCLUDING WARRANTIES OF MERCHANTABILITY AND FITNESS FOR PARTICULAR PURPOSE, WHETHER WRITTEN, ORAL, EXPRESSED, IMPLIED OR STATUTORY, WESTECH ENGINEERING LLC SHALL NOT BE LIABLE ANY CONTINGENT, INCIDENTAL, OR CONSEQUENTIAL DAMAGES FOR ANY REASON WHATSOEVER.

16. PATENTS: WesTech Engineering LLC agrees that it will, at its own expense, defend all suits or proceedings instituted against Purchaser and pay any award of damages assessed against it in such suits or proceedings, so far as the same are based on any claim that the said equipment or any part thereof constitutes an infringement of any apparatus patent of the United States issued at the date of this Agreement, provided WesTech Engineering LLC is given prompt notice in writing of the institution or threatened institution of any suit or proceeding and is given full control of the defense, settlement, or compromise of any such action; and Purchaser agrees to give WesTech Engineering LLC needed information, assistance, and authority to enable WesTech Engineering LLC so to do. In the event said equipment is held or conceded to infringe such a patent, WesTech Engineering LLC shall have the right at its sole option and expense to a) modify the equipment to be non-infringing, b) obtain for Purchaser the license to continue using said equipment, or c) accept return of the equipment and refund to the Purchaser the purchase price thereof less a reasonable charge for the use thereof. WesTech Engineering LLC will reimburse Purchaser for actual out-of-pocket expenses, exclusive of legal fees, incurred in preparing such information and rendering such assistance at WesTech Engineering LLC's request. The foregoing states the entire liability of WesTech Engineering LLC, with respect to patent infringement; and except as otherwise agreed to in writing, WesTech Engineering LLC assumes no responsibility for process patent infringement.

17. SURFACE PREPARATION AND PAINTING: If furnished, shop primer paint is intended to serve only as minimal protective finish. WesTech Engineering LLC will not be responsible for the condition of primed or finish painted surfaces after equipment leaves its shops. Purchasers are invited to inspect paint in shops for proper preparation and application prior to shipment. WesTech Engineering LLC assumes no responsibility for field surface preparation or touch-up of shipping damage to paint. Painting of fasteners and other touch-up to painted surfaces will be by Purchaser's painting contractor after mechanism installation.

Motors, gear motors, and other components not manufactured by WesTech Engineering LLC will be painted with that manufacturer's standard paint system. It is WesTech Engineering LLC's intention to ship major steel components as soon as fabricated, often before drive, motors, and other

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manufactured components. Unless Purchaser can ensure that shop primed steel shall be field painted within thirty (30) days after arrival at the job site, WesTech Engineering LLC encourages the Purchaser to order these components without primer.

WesTech Engineering LLC's prices are based on paints and surface preparations as outlined in the main body of this proposal. In the event that an alternate paint system is selected, WesTech Engineering LLC requests that Purchaser's order advise of the paint selection. WesTech Engineering LLC will then either adjust the price as may be necessary to comply or ship the material unpainted if compliance is not possible due to application problems or environmental controls.

18. CANCELLATION, SUSPENSION, OR DELAY: After acceptance by WesTech Engineering LLC, this proposal, or Purchaser's order based on this proposal, shall be a firm agreement and is not subject to cancellation, suspension, or delay except upon payment by Purchaser of appropriate charges which shall include all costs incurred by WesTech Engineering LLC to date of cancellation, suspension, or delay plus a reasonable profit. Additionally, all charges related to storage and/or resumption of work, at WesTech Engineering LLC's plant or elsewhere, shall be for Purchaser's sole account; and all risks incidental to storage shall be assumed by Purchaser.

19. FORCE MAJEURE: Neither party hereto shall be liable to the other for default or delay in delivery caused by extreme weather or other act of God, strike or other labor shortage or disturbance, fire, accident, war or civil disturbance, act of government, pandemic, delay of carriers, failure of normal sources of supply, complete or partial shutdown of plant by reason of inability to attain sufficient raw materials or power, and/or other similar contingency beyond the reasonable control of the respective parties. The time for delivery specified herein shall be extended during the continuance of such conditions, or any other cause beyond such party's reasonable control.

20. RETURN OF PRODUCTS: No products may be returned to WesTech Engineering LLC without WesTech Engineering LLC's prior written permission. Said permission may be withheld by WesTech Engineering LLC at its sole discretion.

21. BACKCHARGES: WesTech Engineering LLC will not approve or accept backcharges for labor, materials, or other costs incurred by Purchaser or others in modification, adjustment, service, or repair of WesTech Engineering LLC-furnished materials unless such back charge has been authorized in advance in writing by a WesTech Engineering LLC employee, by a WesTech Engineering LLC purchase order, or work requisition signed by WesTech Engineering LLC

22. INDEMNIFICATION: Purchaser agrees to indemnify WesTech Engineering LLC from all costs incurred, including but not limited to court costs and reasonable attorney fees, from enforcing any provisions of this contract, including but not limited to breach of contract or costs incurred in collecting monies owed on this contract.

23. ENTIRE AGREEMENT: This proposal expresses the entire agreement between the parties hereto superseding any prior understandings, and is not subject to modification except by a writing signed by an authorized officer of each party.

24. MOTORS AND MOTOR DRIVES: In order to avoid shipment delays of WesTech Engineering LLC equipment, the motor drives may be sent directly to the job site for installation by the equipment installer. Minor fit-up may be required.

25. EXTENDED STORAGE: Extended storage instructions will be part of information provided to shipment. If equipment installation and start-up is delayed more than 30 days, the provisions of the storage instructions must be followed to keep WARRANTY in force.

26. LIABILITY: Professional liability insurance, including but not limited to, errors and omissions insurance, is not included. In any event, liability for errors and omissions shall be limited to the lesser of $100,000USD or the value of the particular piece of equipment (not the value of the entire order) supplied by WesTech Engineering LLC against which a claim is sought.

27. ARBITRATION NEGOTIATION: Any controversy or claim arising out of or relating to the performance of any contract resulting from this proposal or contract issued, or the breach thereof, shall be settled by arbitration in accordance with the Construction Industry Arbitration Rules of the American Arbitration Association, and judgment upon the award rendered by the arbitrator(s) may be entered to any court having jurisdiction.

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WESTECH

3665 SOUTH WEST TEMPLE

Salt Lake City, Utah 84115
(801) 265-1000

CLIENT:	PLANT MILLER	REV	BY	CHECKED	REASON	DATE
PROJECT TITLE:	FGD WASTEWATER VSEP TREATMENT CONVERSION	A	SW17	SO74	Initial Submittal	2/7/2023
PROJECT NO.:	24877	B	SO74	SW17	Includes Southern Company's MB	2/24/2023
DOCUMENT NAME:	24877-Mass Balance	C	SO74	SW17	Update Mass Flow Column 9	2/28/2023
DOCUMENT NUMBER:	-					

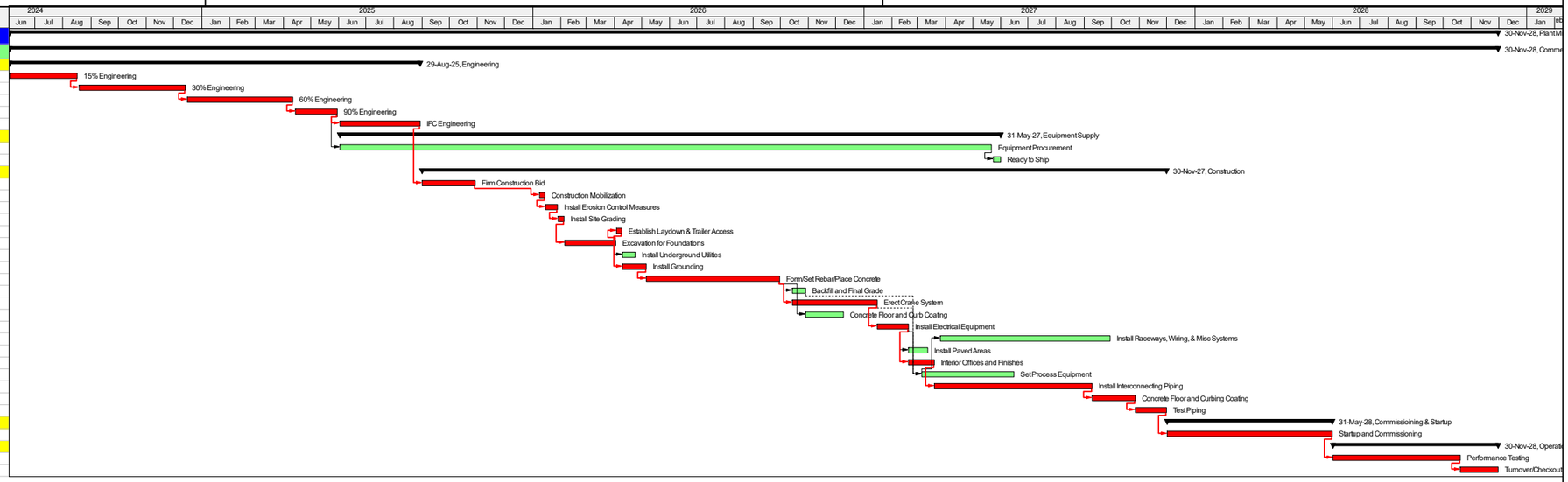
Stream ID	1. INFLUENT FROM PHYS/CHEM SYSTEM	2. VSEP SYSTEM INFLUENT (INCLUDES RO REJECT RECIRC)	3. VSEP SYSTEM EFFLUENT	4. VSEP SYSTEM REJECT	5. AVARA CONCENTRATE	6. AVARA DISTILLATE	7. FLYASH TO SOLIDIFICATION PROCESS (BY OTHERS)	8. LIME TO SOLIDIFICATION PROCESS (BY OTHERS)	9. TOTAL SOLIDIFICATION MIX (18% BRINE, 77% FLYASH, and 5% LIME) (BY OTHERS)
Design (Max) Flow Rate, Continuous (GPM)	608.0	792.0	519.0	89.0	23.1	65.9	163 (1307.6 cuft/hr)	6.2 (50 cuft/hr)	192.5 (1543.9 cuft/hr)
Design (Max) Mass Flow Rate, Continuous (lbs/hr)							58843 lbs/hr	3821 lbs/hr	76419 lbs/hr
Maximum TDS (mg/L)	10000.0	9019.5	2.3	68211.9	263366.4	~10			
Solids SG	2.40	2.40	2.40	2.40	2.40	2.40	0.72	3.34	-
Liquid SG	1.0	1.0	1.0	1.0	1.0	1.0	-	1.0	-
pH	5.5-8.5	5-8	5-8	6-8	6-8	6-8	-	-	-
Intermittent Flow Rate *NOTE 1									
NOTES	1. If the intermittent flowrate is greater than the Design (Max) flow, this is the flow the system will be designed to.								

Southern Company - Plant Miller Pre-Feasibility Study

Plant Miller Pilot Schedule

WesTech Document Name: Project Schedule
WesTech Document Number: 24877-SCH01
Version: As of 14-Feb-23 / 17:08

Activity ID	Activity Name	Original Duration	Remaining Duration	Start	Finish
Plant Miller Pre-Feasibility Study		1174	1174	03-Jun-24	30-Nov-28
Commercial Project		1174	1174	03-Jun-24	30-Nov-28
Engineering		325	325	03-Jun-24	29-Aug-25
A1000	15% Engineering	55	55	03-Jun-24	16-Aug-24
A1010	30% Engineering	85	85	19-Aug-24	13-Dec-24
A1020	60% Engineering	85	85	16-Dec-24	11-Apr-25
A1030	90% Engineering	35	35	14-Apr-25	30-May-25
A1050	IFC Engineering	65	65	02-Jun-25	29-Aug-25
Equipment Supply		521	521	02-Jun-25	31-May-27
A1110	Equipment Procurement	515	515	02-Jun-25	21-May-27
A1115	Ready to Ship	6	6	24-May-27	31-May-27
Construction		587	587	01-Sep-25	30-Nov-27
A1040	Firm Construction Bid	43	43	01-Sep-25	29-Oct-25
A1130	Construction Mobilization	5	5	08-Jan-26	14-Jan-26
A1140	Install Erosion Control Measures	10	10	15-Jan-26	28-Jan-26
A1150	Install Site Grading	5	5	29-Jan-26	04-Feb-26
A1160	Establish Laydown & Trailer Access	5	5	03-Apr-26	09-Apr-26
A1170	Excavation for Foundations	41	41	05-Feb-26	02-Apr-26
A1180	Install Underground Utilities	10	10	10-Apr-26	23-Apr-26
A1190	Install Grounding	19	19	10-Apr-26	06-May-26
A1200	Form/Set Rebar/Place Concrete	105	105	06-May-26	30-Sep-26
A1210	Backfill and Final Grade	10	10	14-Oct-26	28-Oct-26
A1220	Erect Crane System	67	67	14-Oct-26	15-Jan-27
A1230	Concrete Floor and Curb Coating	30	30	28-Oct-26	09-Dec-26
A1240	Install Electrical Equipment	25	25	15-Jan-27	19-Feb-27
A1250	Install Raceways, Wiring, & Misc Systems	133	133	26-Mar-27	29-Sep-27
A1260	Install Paved Areas	15	15	19-Feb-27	12-Mar-27
A1270	Interior Offices and Finishes	20	20	19-Feb-27	19-Mar-27
A1280	Set Process Equipment	72	72	05-Mar-27	15-Jun-27
A1290	Install Interconnecting Piping	124	124	19-Mar-27	09-Sep-27
A1300	Concrete Floor and Curbing Coating	34	34	09-Sep-27	27-Oct-27
A1310	Test Piping	24	24	27-Oct-27	30-Nov-27
Commissioining & Startup		130	130	01-Dec-27	31-May-28
A1120	Startup and Commissioning	130	130	01-Dec-27	31-May-28
Operations Optimization		130	130	01-Jun-28	30-Nov-28
A1400	Performance Testing	100	100	01-Jun-28	19-Oct-28
A1410	Turnover/Checkout	30	30	19-Oct-28	30-Nov-28



Actual Work
Remaining Work
Critical Remaining Work
Milestone
Summary

TASK filter: All Activities

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APPENDIX B

Georgia Power Company - Plant Bowen Membrane Cost Study

First Page – Total Project Cost

WesTech Budgetary Study Report

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CECEN285 - Design & Technical Services - Detailed Engineering	0	HR		$0	$0	0	$0	$5,706,278	$0	$5,706,278
CECEN291 - Outsourced Detailed Engineering	0	HR		$0	$0	0	$0	$16,500,000	$0	$16,500,000
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COCIN150 - T&PS - Construction Management	0	HR		$0	$0	0	$0	$8,151,826	$0	$8,151,826
COCIN151 - Temporary Construction	0	HR		$0	$0	0	$0	$0	$4,891,095	$4,891,095
COCPK006 - Mechanical			17,500	$1,077,315	$187,539,681	0	$94,956,035	$0	$0	$283,573,031
COCPK020 - Switchyard, Distribution & Transmission			0	$0	$0	0	$20,000,000	$0	$0	$20,000,000
COCPK029 - Scaffolding			0	$129,278	$0	0	$0	$0	$0	$129,278
COCPK030 - Contractor Indirects			0	$788,564	$13,182,488	0	$0	$0	$0	$13,971,052
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TSSUC750 - Start-up and Commissioning	0	HR	0	$0	$0	0	$0	$3,260,730	$0	$3,260,730
TSSUC752 - Outsourced Start-Up and Commissioning	0	HR	0	$0	$0	0	$0	$6,000,000	$0	$6,000,000
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CPCOC301 - E&S				$68,627	$6,904,209		$3,954,125	$1,362,763	$168,238	$12,457,962
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CPCOC304 - Escalation				$118,830	$11,954,815		$6,846,668	$2,359,659	$291,309	$21,571,280
CPCOC305 - Contingency				$598,547	$60,216,651		$34,486,811	$11,885,650	$1,467,329	$108,654,987
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CPCOC300 - AFUDC/IDC				$431,820	$43,443,066		$24,880,374	$8,574,856	$1,058,598	$78,388,713
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Georgia Power

Plant Bowen Budgetary Study

Euharlee, GA

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WESTECH®

Project Number: 24926 rev 1
Thursday, May 25, 2023

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Technical Proposal

Design Basis

The objective of this document is to provide Southern Company Services with a conceptual design and budgetary level cost estimate of the deliverables associated with potentially converting Georgia Power Company Plant Bowen flue gas desulfurization (FGD) wastewater treatment system to utilize membrane technology, considering the 2020 ELG Rule's Voluntary Incentives Program (VIP) compliance option and the 2023 Proposed ELG Rule.

Reference Standards & Codes

- ANSI/ASME American Society of Mechanical Engineers B31.1 Power Piping Code
- American Institute of Steel Construction (AISC) specification for the Design, Fabrication and Erection of Structural Steel for Buildings
- AWS - American Welding Society: D1.1 - "Structural Welding Code - Steel".
- American Iron and Steel Institute (AISI) specification for the Design of Light Gauge Cold-Formed Steel Structural Members
- NEMA - National Electrical Manufacturers Association: MG 1 - "Motors and Generators".
- American Concrete Institute (ACI) Building Code requirements for reinforced Concrete ACI 318-63
- AISC Manual of Steel Construction
- ASME B16.5 Pipe Flanges and Flanged Fittings
- ASME B30-2 Overhead and Gantry Cranes
- Underwriters Laboratories (UL): 10B - "Standard for Safety Fire Tests of Door Assemblies".

NEC National Electric CodeNFPA

- 70 - "National Electrical Code".

National Fire Protection Association:

- 80 - "Standard for Fire Doors and Fire Windows".
- 101 – "Life Safety Code".
- U.S. Department of Labor, Occupational Safety and Health Administration (OSHA): 29 CFR, Title 29 - "Occupational Safety and Health Standards".

Governing codes for project location:

- 2006 International Building Code with Georgia amendments.
- Including and not limited to verifying and designing for the Seismic Site Class in accordance with IBC Section 1615.

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- NFPA 101 – “Life Safety Code for Buildings”.
- OSHA - Occupational Safety and Health Administration.

WesTech General Specifications

- D-11 DESIGN FUNCTIONAL TAGS AND DESCRIPTIONS
- FIELD LINING SPECIFICATION
- PAINT COLOR GUIDANCE
- Pavement Structures
- Preferred vendor list
- M_2_09 MECHANICAL INSULATION

WesTech Electrical Specifications

BGE Drawings

- BGE1001
- BGE1003
- BGE1004
- BGE1005
- BGE1006
- BGE1007
- BGE1008
- BGE1011

Electrical Standards

- E-1-02 Raceway Naming
- E-1-03 Raceway Design Standard
- E-1-04 Circuit Naming
- E-1-05 Plant Circuitry
- E-1-06 Cable and Cable Bus
- E-1-07 Transformers
- E-1-08 Direct Current Distribution Systems Standard
- E-1-09 Fuses
- E-1-10 Lighting and Receptacles
- E-1-11 Grounding Standard

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- E-1-13 Hazardous Classified Locations
- E-2-03 Cable Code Definition
- E-2-04 Electrical Mark Numbers
- E-2-10 Arc Flash Mitigation (1)

Installation Standards

- Standard_Spec_SECTION_260000_Gen_Req
- Standard_Spec_SECTION_260526_grounding_system
- Standard_Spec_SECTION_260533_conduit
- Standard_Spec_SECTION_261213_outdoor_xfrmers
- Standard_Spec_SECTION_262716_boxes
- Standard_Spec_SECTION_265000_lighting_fixtures
- Standard_Spec_SECTION_266010_motors
- Standard_Spec_SECTIONS_2605xx_electrical_cables

Other Specifications

- Cable Specification
- G95797 LV MCC Detailed Spec
- G95797 LV MCC General Spec
- Heat Tracing Specification

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Process Design

Below is a table of the influent water process design criteria provided as part of the request for quote that will discharge from the Plant's existing FGD wastewater physical/chemical treatment system and feed the new Membrane Treatment System (MTS).

Table 1. Influent Design Criteria Values

Parameter	Units	Normal (Cycled Down, Typ. Values, 100% Flow)	Design Case 1 (Cycled Down, Max. Values, 100% Flow)
Flow, total leaving Phys/Chem	gpm	750	1,500
Total Dissolved Solids (TDS)	mg/L	15,000-30,000*	8,000-14,000*
pH	S.U.	6.7-7.5	6.7-7.5
Total Suspended Solids (TSS)	mg/L	<10	<10
Oil & Grease	mg/L	<1	<1
As, total	µg/L	5	5
Hg, total	ng/L	2,500**	2,500
Nitrates/Nitrites	mg/L as N	33	22
Se, total	µg/L	50-500	150-1,000
Chloride	mg/L	<14,000	<8,000
Bromide	mg/L	40	30
Calcium, total	mg/L as CaCO3	<10,600	<6,500
Magnesium, total	mg/L as CaCO3	<1,075	<660
Temperature	Deg F	50 - 120	50 - 120

Notes:

** - Typical cycled down range is 200 to 2,500 ppt.

* - Recommended level of softening required to meet target

The treatment system proposed herein is designed in accordance with the Design Case 1 constituent levels and maximum flowrate (1,500 gpm). This design case reflects conditions observed when all the FGD scrubber systems are cycled down and all treated effluent is discharged to the river in the case of 2020 ELG VIP Option, or reused within the plant in the case of 2023 Proposed ELG Rules. All brine generated is encapsulated.

The following table outlines effluent performance criteria from the Membrane Treatment System.

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Table 2. VSEP System Effluent

(Combined Permeate and Distillate Stream)

Parameter	Units	Maximum for any 1 Day	Maximum Rolling 30 Day Average
Total Dissolved Solids (TDS)	mg/L	306	149
pH	S.U.	6 - 9	6 - 9
Total Suspended Solids (TSS)	mg/L		
Oil & Grease	mg/L		
As, total	µg/L	5	NA
Hg, total	ng/L	23	10
Nitrates/Nitrites	mg/L as N	2	1.2
Se, total	µg/L	10	NA
Chloride	mg/L		
Bromide	mg/L	0.2	NA

Please note, these effluent limits are assumed from the 2020 ELG VIP for reference only and do not constitute a process guarantee. WesTech can provide a formal process guarantee upon request.

In the event 2023 Proposed ELG Rules are adopted, zero discharge limits require the reuse of permeate and distillate on site.

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Assumptions

- The existing physical / chemical treatment will remain in service as pre-treatment ahead of the new Membrane Treatment System.
- Modifications will be made to the physical / chemical treatment train to improve performance of the clarifier and allow for metals removal and softening to precipitate hardness.
- Unless otherwise stated, all subsystems and modular components will be provided as manufacturer's standard and will not follow any additional custom specifications.

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Plant Design

Table 3. List of Major Equipment Vendors

Major Equipment Vendors	
Type	**Vendor**
Vibrating Membranes (VSEP)	New Logic
Spiral RO Membranes	New Logic
Thermal Evaporator (AVARA)	Purestream
Process Pumps	Grundfos, or Equal
Chemical Metering Pumps	Grundfos, or Equal
Silos/Slakers	Chemco, or Equal
PLC	Allen Bradley or Equal
Butterfly Valves	Bray or Equal
Ball Valves	Flow-Tek or Equal
Analytical Instrumentation	Endress+Hauser or Equal
Pressure Instrumentation	Endress+Hauser or Equal
Flow Instrumentation	Endress+Hauser or Equal
Level Instrumentation	Endress+Hauser or Equal

*Final vendor selections may differ based on detailed engineering. WesTech may utilize an 'or equal' if needed.

Sparing Philosophy

In general, WesTech will provide equipment with 2 x 50% sparing. Equipment not in 2 x 50% trains will at minimum treat 100% of design flow with expected equipment under routine cleaning (CIP), and will treat a minimum of 50% of design flow in all cases.

Pumps

- ASME B73 or pump manufacturer standards will be considered, as applicable.

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Piping

Table 4. Plant Bowen Piping Summary Design Basis

Piping Summary	
Service	**Pipe Material**
Process, Above Ground, Inside	HDPE
Process, Above Ground, Outside	HDPE
Process, Underground,	HDPE
Process, Underground, Treated, Outfall	HDPE
Process, Underground, Treated, Outfall	HDPE
Process, Above Ground, Skidded Materials	2205
Process, Above Ground, Inside, MTS Boundary Limits	2205
Chemical, Hydrogen Peroxide	Tube: PVDF
Chemical, Ferric Chloride	Tube: Polypropylene (CPVC on Skid)
Chemical, Sodium Hydroxide	Tube: Polypropylene (CPVC on Skid)
Chemical, Sulfuric Acid	Tube: PVDF
Chemical, Organosulfide	Tube: Polypropylene (CPVC on Skid)
Chemical, Ferric Sulfate	Tube: Polypropylene (CPVC on Skid)
Chemical, Sodium Sulfate	Tube: Polypropylene (CPVC on Skid)
Chemical, Sodium Bisulfite	Tube: Polypropylene (CPVC on Skid)
Polymer, <= 1/2-in.	Tube: Polypropylene (CPVC on Skid)
Polymer, > 1/2-in.	Tube: Polypropylene (CPVC on Skid)
Service Water	CS
Air, Service, >= 1/2-in.	304SS
Air, Instrument, >= 1/2-in.	304SS
Air, Instrument, < 1/2-in. (Pressure Regulated)	Tube: 304SS (SwageLok)
Potable Water, Above Ground, Inside, < 2-in	Copper
Potable Water, Underground	HDPE
Fire Water, Inside, Sprinkler	CS
Sewer	HDPE

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Battery Limits

The following tie points have been identified and will be specified with generalized (not to exceed) conditions for the purposes of developing engineering. The purchaser will be responsible for providing not to exceed values where indicated in the table below. Final tie point conditions will be identified in the Tie Point List which will be provided by WesTech with a 30% engineering package.

Table 5. Plant Bowen Battery Limit Tie Points

Tie Points						
#	**Tie-Point**	**Max Flow (GPM)**	**Max Pressure (ft H2O)**	**Location**	**Grade Elevation (ft)**	**Connection Type**
1	Inlet to Influent Pump Skid	1500	TBD	BTS Pad	TBD	FF, ANSI 150
	Note 1: Connection within 10’ of the WWTS boundary					
2	Final Effluent to Existing pipeline to FGD Effluent Tank	1033	TBD	BTS Pad	TBD	FF, ANSI 150
	Note 1: Connection within 10’ of the WWTS boundary					
3	AVARA Brine Final Effluent	84	TBD	TBD	TBD	FF, ANSI 150
	Note 1: Connection within 10’ of the WWTS boundary					
4	Service Water	21	TBD	BTS Pad	TBD	FF, ANSI 150
	Note 1: Connection within 10’ of the WWTS boundary					
5	Sumps					
6	Compressed Air					
	Note 1: At BTS Pad. VSEP requirements are 66 CFM.					
7	Electrical			Note 1		
	Note 1: WT will determine location on field wiring plans (preliminary) with an engineering package after execution of the contract. Other: WT will supply a 480V 3PH 60 HZ distribution panel for all loads inside the battery limits of the WWTS. Purchaser will be responsible for powering this panel based on not to exceed loads that will be provided on the single line diagram with an engineering package after execution of contract.					
8	Communication			Note 1		
	Note 1: WT will determine location on field wiring plans (preliminary) with an engineering package after execution of the contract Other: Tie points will be at WT supplied PLC. Purchaser will be responsible for communication cable with any systems outside of 10’ of WesTech’s treatment boundary.					

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Site Information

Table 6. Plant Bowen Site Specific Information

Operating Company	Georgia Power Company		
Plant	Plant Bowen		
Units	1-4		
Street Address	317 Covered Bridge Road		
City	Euharlee		
County	Bartow		
State	Georgia		
Zip Code	30120		
Grade Elevation	306’-0” ASL		
Railroad Access	Yes (CSX)		
Barge Access	No		
	Minimum	**Typical**	**Maximum**
Ambient Temperature (°F)	-10	75	107
Indoor Temperature (°F)	45	90	110
Ambient Relative Humidity (%)	30	60	100
Barometric Pressure (psia)		14.535	
Average Monthly Rainfall (in)		4.67	
Max. Daily Rainfall (25yr/24hr, in)			7.11
Max. Single Rainfall Event (10yr/2hr, in)			3

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Scope Split

Table 7. Plant Bowen Project Execution Scope Matrix

Scope Matrix				
Work Category	**Functional Design/Input**	**Detailed Design**	**Supply**	**Install/ Perform**
Equipment Supply	WesTech	WesTech	WesTech	3rd Party Construction Contractor
Earthwork	WesTech	WesTech	WesTech	3rd Party Construction Contractor
Concrete	WesTech	WesTech	WesTech	3rd Party Construction Contractor
Interconnecting Piping (plant)*	WesTech	WesTech	WesTech	3rd Party Construction Contractor
Interconnecting piping (to plant)**	Owner	Owner	Owner	Owner
Interconnecting Wiring*	WesTech	WesTech	WesTech	3rd Party Construction Contractor
Interconnecting Wiring (to plant)**	Owner	Owner	Owner	Owner
Main Power Distribution	WesTech	WesTech	WesTech	3rd Party Construction Contractor
Transformer	WesTech	Owner	Owner	Owner
MCC	WesTech	WesTech	WesTech	3rd Party Construction Contractor
PLC	WesTech	WesTech	WesTech	3rd Party Construction Contractor
Temporary Structures	WesTech	WesTech	WesTech	3rd Party Construction Contractor
Permitting	WesTech	WesTech	Owner	Owner

*Within boundary limits of the plant

**Outside boundary limits of the plant (See Battery Limits)

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Process Flow Diagram

[Attached separately until final draft]

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Site Plan

[Attached separately until final draft]

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Process Description

Physical / Chemical Treatment (Existing)

Softening to Lower TDS

Precipitation of solids by caustic and soda ash softening lowers the hardness and therefore Total Dissolved Solids (TDS) will be lowered as well. Dosage of caustic and soda ash will be in reaction tanks upstream of the clarifier. Metals precipitation can be improved by the addition of organosulfide. The clarifier is followed by continuous backwash sand filters. pH adjustment with acid takes place in the Stage 1 VSEP Feed Tank which also serves as an attenuation tank.

Membrane Treatment System

Stage 1 VSEP Feed Tank

The influent for the system goes into the Stage 1 VSEP Feed Tank. The Stage 1 VSEP Feed Tank is fed by the multimedia filter effluent. The tank also receives flow from the concentrate of the Stage 3 Reverse Osmosis (RO) membrane. Acid is added to the Stage 1 tank for any necessary pH adjustment. Antiscalant and bisulfite are dosed in the header to prevent scaling and reduce chlorine respectively.

The Stage 1 Low Pressure VSEPs pull from the Stage 1 VSEP Feed Tank. To prevent cavitation of the VSEP feed pumps, a booster pump on the feed line starts when both low pressure VSEP membranes are active.

Stage 1 Low Pressure VSEP

The Low Pressure VSEP Membranes use membrane filtration to achieve liquid/solid separation. They employ a unique vibrating filter pack that produces a high shear rate on the membrane surface which inhibits membrane surface fouling and induces greater filtrate flow rates during the filtration process.

The Stage 1 Low Pressure VSEPs discharge two streams: permeate (filtrate or product) and concentrate (brine or retentate). The VSEP concentrate is sent to the Stage 2 High Pressure VSEP Feed Tank. The permeate is sent to the Stage 3 Spiral RO Feed Tank.

The membranes will need to be cleaned occasionally to remove accumulated foulants or scaling. There are two modes of cleaning, flush and CIP. Flush is a lower pressure single pass step where heated RO permeate is sent to the system for removal of foulants and/or scaling. CIP is a lower pressure recirculation step where heated RO permeate mixed with cleaning chemicals is sent to the system for removal of more stubborn foulants.

Stage 2 High Pressure VSEP Feed Tank

The Stage 2 High Pressure VSEP Feed Tank receives flow from the Low Pressure VSEP membranes concentrate. This tank is the feed tank to the Stage 2 High Pressure VSEP membranes for further volume reduction. Antiscalant is dosed after the Feed Tank to prevent scaling.

Stage 2 High Pressure VSEP

The High Pressure VSEP membranes use membrane filtration to achieve liquid/solid separation. They employ a unique vibrating filter pack that produces a high shear rate on the membrane surface which inhibits membrane surface fouling and induces greater filtrate flow rates during the filtration process.

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Stage 2 membranes operate at a higher pressure than Stage 1 due to the higher dissolved solids loading in the brine feed that must be rejected at the membrane surfaces.

The Stage 2 High Pressure VSEPs discharge two streams: permeate (filtrate or product) and concentrate (brine or retentate). The Stage 2 High Pressure VSEP concentrate is sent to the Concentrate Storage Tank. The permeate is sent to the Stage 3 Spiral RO Feed Tank.

The membranes will need to be cleaned occasionally to remove accumulated foulants or scaling. There are two modes of cleaning, flush and CIP. Flush is a lower pressure single pass step where heated RO permeate is sent to the system for removal of foulants and/or scaling. CIP is a lower pressure recirculation step where heated RO permeate mixed with cleaning chemicals is sent to the system for removal of more stubborn foulants.

Stage 3 Spiral RO Feed Tank

The Stage 3 Spiral RO Feed Tank receives flow from the Stage 1 Low Pressure VSEP permeate, Stage 2 High Pressure VSEP permeate, and Stage 4 Spiral RO concentrate. This tank is the feed tank to the Stage 3 Spiral RO membranes for further polishing.

Stage 3 Spiral RO

The Stage 3 Spiral RO is the first stage of polishing after the VSEP membranes. There are 3 stages of RO (stage 3,4, and 5) total. The last stage is required to lower the mercury concentration to the required effluent quality. The same principles of operation apply to this membrane as the Stage 1 Low Pressure VSEP membranes. The feed stream is separated into 2 discharge streams: permeate and concentrate. The permeate is sent to the Stage 4 Spiral RO Feed Tank. The concentrate is recycled back to the Stage 1 Low Pressure VSEP Feed Tank for additional processing. The Stage 3 Spiral RO is cleaned in a similar manner to the Stage 1 and 2 VSEP membranes.

Stage 4 Spiral RO Feed Tank

The Stage 4 Spiral RO Feed Tank receives flow from the Stage 3 Spiral RO permeate, and Stage 5 Spiral RO concentrate. This tank is the feed tank to the Stage 4 Spiral RO membranes.

Stage 4 Spiral RO

The Stage 4 Spiral RO is the second stage of polishing after the VSEP membranes. The same principles of operation apply to this membrane as the Stage 3 Spiral RO membranes. The feed stream is separated into 2 discharge streams: permeate and concentrate. The permeate is sent to the Stage 5 Spiral RO Feed Tank. The concentrate is recycled back to the Stage 3 Spiral RO Feed Tank for additional processing. The Stage 4 Spiral RO is cleaned in a similar manner to the previous system membranes.

Stage 5 Spiral RO Feed Tank

The Stage 5 Spiral RO Feed Tank receives flow from the Stage 4 Spiral RO permeate. This tank is the feed tank to the Stage 5 Spiral RO membranes.

Stage 5 Spiral RO

The Stage 5 Spiral RO is the third and final stage of polishing after the VSEP membranes. The same principles of operation apply to this membrane as the previous spiral RO membranes. The feed stream is separated into 2 discharge streams: permeate and concentrate. The permeate is sent to the Permeate Forwarding Storage Tank. This permeate water will meet the effluent limits assumed from the 2020 ELG

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VIP. The concentrate is recycled back to the Stage 4 Spiral RO Feed Tank for additional processing. The Stage 5 Spiral RO is cleaned in a similar manner to the previous system membranes.

Concentrate Storage Tank

The Concentrate Storage Tank will receive the concentrate flow from the Stage 2 High Pressure VSEP membranes. It will feed the AVARA system.

Thermal Evaporator (AVARA)

Parallel thermal evaporators will be used to reach the appropriate flow rate. The thermal evaporators will be AVARA systems. AVARAs use advanced vapor recompression technology for thermal evaporation and to concentrate a brine stream. AVARA systems are fully automated and come as a fully skidded solution.

The AVARAs will be fed by the Concentrate Storage Tank. The brine from the AVARAs will go to the Brine Storage Tank while the distillate will be fed to the permeate forwarding tank.

The Thermal Evaporator is used to concentrate brine from the High Pressure VSEP membranes to the point just before saturation. It is expected that the concentration of TDS could reach up to 250,000 ppm.

The Thermal Evaporators will heat the feed concentrate to the point of boiling. Water is pumped through a 500 mesh self-cleaning filter and split into two streams. One stream is sent through the distilled heat-exchanger while the other is sent through the brine heat exchanger. The streams recombine and are sent to the core tank section of the AVARA.

In the core tank section, water is boiled to create a saturated vapor. Vapor is compressed to between 3 and 7.5 PSI with a blower. The compressed vapor is then forced through dimpled plates. As the vapor moves through the plates, it condenses. The condensed and distilled water is then pumped through the feed heat exchangers and out of the system as effluent to the Permeate Forwarding Storage Tank.

Operators watch the pressures within the AVARA. Changes in pressure can change production rate and temperature making it a key process condition. Operators can adjust relief valves, heater temperature, blower speed, and the heat exchanger by-pass valve to optimize system pressures.

With much of the feed water evaporated, condensed, and discharged, the brine left in the AVARA will continue to recirculate through the heat exchanger. Once it is concentrated to a point just before saturation, it is pumped out of the system. A control valve will control brine discharge flowrate and will be set to maintain the desired brine concentration. Brine will be sent to the Brine Storage tank where it will then be processed through the Solidification Batch Plant.

Permeate Forwarding Storage Tank

The Permeate Forwarding Storage Tank will receive flow from the Stage 5 Spiral RO membranes and the AVARA distillate. The Permeate Forwarding Storage Tank supplies the Permeate Forwarding Pump Skid that sends water to the FGD Effluent Tank located in the existing Phys/Chem Treatment Area.

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Solidification Plant

The solidification plant will work to collect and meter dry solidification materials and brine for loading into a cement mixer. These solidification materials are Flyash, Lime, and standard concrete conditioning additives. Flyash with small amounts of lime will be used as the primary solidification material. If Flyash is not readily available, Cement and lime can be used as an alternative. These materials will be stored in silos above a weigh hopper. These materials will be metered into the weigh hopper at a known quantity. This hopper will feed the dry material into cement trucks followed by brine for mixing. The solidification plant will be designed for fugitive dust control. The cement truck will transport the mixed material for disposal. The solidified brine mixture will pass both the paint filter test and the Toxicity Leaching Characteristic Procedure prior to being landfilled in an on-site facility.

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Equipment List

Table 8. Plant Bowen Budgetary Study Major Equipment List

Major Equipment List

Item	Description	Materials	Size
Reaction Tanks	Cylindrical open top, flat bottom tank, shop built, with mixer	FRP tank, rubber lined carbon steel mixer	3 Tanks 15,000 gal 12'D x 20'
Flocculating Clarifier Mechanisms	Curved rake blades on posts, paddle wheel type flocculator in existing feedwell, dual shaft drive 83,500 ft-lbs with 10 ton lift	Rubber lined carbon steel with some FRP components	Modifications to 3 existing clarifiers 38'D x 18'
Caustic Storage / Feed System	Cylindrical closed top tank	HDPE	1 x 100% 12,000 gal 12'D x 16' – 7.75"H
Soda Ash Silo	Heavy Soda Ash Cone Bottom Sloped Roof	Carbon steel	2 x 50% 14'D x 78' storage height
Influent Pump Skid	Centrifugal	SS	1 Skid 2 x 100% pumps per skid @ 20 psi 1500 gpm 10 HP each
Stage 1 VSEP Feed Tank	Open top cylindrical tank (existing) Mixer (new)	FRP Rubber lined steel	1 x 100% 174,000 gal 30'D x 34'H
Stage 1 VSEP Feed & Booster Pumps	Vertical Multi-Stage Centrifugal	SS	7 Skids 4 x 25% pumps per skid @ 450 Total PSI 1500 gpm total 200 HP each
Stage 1 Low Pressure VSEP Membranes	Vibrating disc membrane filters	Varies	7 Skids 8 Modules per Skid 52 of 56 Modules (84") (4 spare/future) 1,867 gpm total 8 x 20 HP Vibration Motors

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Item	Description	Materials	Size
Stage 2 High Pressure VSEP Feed Tank	Cylindrical closed top tank	FRP	1 x 100% 55,000 gal 18'D x 30'H
Stage 2 High Pressure VSEP Feed Pumps	Positive displacement	SS	16 skids 4 x 25% pumps per skid @ 750 Total PSI 933 gpm total 200 HP each
Stage 2 Membranes High Pressure VSEP Membranes	Vibrating disc membrane filters	Varies	16 Skids 4 Modules per Skid 61 of 64 Modules (17") (3 spare/future) 933 gpm total 4 x 20 HP Vibration
Stage 3 Spiral RO Feed Tank	Flat Bottom Tank (Knock Down) No Roof	FRP	1 x 100% 100,000 gal 25'D x 30'H
Stage 3 Spiral RO Feed & Booster Pumps	Vertical Multi-Stage Centrifugal	SS	On Spiral RO Skid (12x) 2 pumps per skid @ 300 PSI 1667 gpm total 50 HP each
Stage 3 Spiral RO Membranes	S-18000 Spiral System Spiral-wound membrane filters Pre-Screen Basket Strainers Included	Varies	12 Skids 45 Elements per skid 1667 gpm total
Stage 4 Spiral RO Feed Tank	Flat Bottom Tank (Knock Down) No Roof	FRP	1 x 100% 100,000 gal 25'D x 30'H
Stage 4 Spiral RO Feed & Booster Pumps	Vertical Multi-Stage Centrifugal	SS	On Spiral RO Skid (10x) 2 pumps per skid @ 200 PSI 1483 gpm total 40 HP each

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Item	Description	Materials	Size
Stage 4 Spiral RO Membranes	S-18000 Spiral System Spiral-wound membrane filters Pre-Screen Basket Strainers Included	Varies	10 Skids 45 Elements per skid 1483 gpm total
Stage 5 Spiral RO Feed Tank	Flat Bottom Tank (Knock Down) No Roof	FRP	1 x 100% 100,000 gal 25'D x 30'H
Stage 5 Spiral RO Feed & Booster Pumps	Vertical Multi-Stage Centrifugal	SS	On Spiral RO Skid (8x) 2 pumps per skid @ 200 PSI 1216 gpm total 40 HP each
Stage 5 Spiral RO Membranes	S-18000 Spiral System Spiral-wound membrane filters Pre-Screen Basket Strainers Included	Varies	8 Skids 45 Elements per skid 1216 gpm total
Permeate Forwarding Storage Tank	Flat Bottom Tank (Knock Down) No Roof	FRP	1 x 100% 68,000 gal 20'D x 30'H
Permeate Forwarding Pumps	Vertical Multi-Stage Centrifugal	SS	2 x 100% @ 60 PSI 1033 gpm 75 HP
Evaporator Feed Pump	Horizontal Centrifugal	SS	3x50% @ 60PSI 234 gpm each 20 HP each
Evaporator Booster Pumps	Horizontal Centrifugal	SS	28 @ 43PSI 30 gpm each 5 HP each
Concentrate Storage Tank	Flat Bottom Tank (Knock Down)	FRP	1 x 100% 150,000 gal 30'D x 30'H
Mixer	Hydrofoil Mixer	Rubber lined steel	25 HP

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Item	Description	Materials	Size
Evaporators	AVARA Advanced Vapor Recompression System	Varies	14 30 gpm each 12'W x 50'L x 10'H each 84 GPM Brine Flow total *Power Requirements:* 480V/3 Ph/ 600 Amp Breaker x (6) 3600 Amp Total MVR Vapor Blowers A/B: 200 HP Core Heaters 6 x 40 kW
Distillate Discharge Pump(s)	Horizontal Centrifugal	SS	14 *25 gpm @ 45 psi, 5 HP*
Concentrate (Brine) Recycle/Discharge Pump(s)	Horizontal Centrifugal	SS	14 *10 gpm @ 60 psi, 5 HP*
Stage 1 Low Pressure VSEP Clean-in-Place System	Vertical Multi-Stage Centrifugal Pump	316 SS Pump	QTY – 4 Systems 1 x 100% pumps each @ 250 PSI 60 gpm 20HP
	pH Sensor Level Sensor	HDPE Tank/Piping	260-gal HDPE Tank 3'D x 6' – 4"H ~2010 lb each
Stage 2 High Pressure VSEP Clean-in-Place Systems	Vertical Multi-Stage Centrifugal Pump	316 SS Pump	QTY – 2 Systems 1 x 100% pumps each @ 250 PSI 60 gpm 20HP
	pH Sensor Level Sensor	HDPE Tank/Piping	200-gal HDPE Tank each 3'Dx 4' – 6"H ~2010 lb each

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Item	Description	Materials	Size
Stage 3-5 Spiral RO Clean-in-Place System	Vertical Multi-Stage Centrifugal Pump	316 SS Pump	QTY – 1 Systems 1 x 100% pumps each @ 185 PSI 60 gpm 20HP
	pH Sensor	HDPE Tank/Piping	200-gal HDPE Tank each 3'D x 4'– 6"H
	Level Sensor		~2010 lb each
Water Heating System		Varies	400 HP max Tank – 6,100 gal 10'D x 12' – 8"H

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Table 9. Chemical Feed Systems and Tankage Equipment List

Chemical Feed Systems & Tankage

Item	Description	Materials	Size
Organosulfide	Tote Fed	HDPE Skid, Sch 80 PVC Plumbing	2 x 100% Metering pumps (plus shelf spare) 1 gph
Soda Ash	Silo	Carbon Steel	274 gpm
Caustic	Cylindrical Closed Top Chemical Storage Tank	HDPE	3.4 gpm 9500 gal
Hydrochloric Acid	Tote Fed		0.6 gpm
VSEP AntiScalant 1 Feed System	Tote Fed 100% Active	HDPE Skid, Sch 80 PVC Plumbing	2 x 100% Metering pumps (plus shelf spare) 1 gph 0.5 HP each
VSEP pH Adjust Feed System	Tote Fed Sulfuric Acid 93% Active	HDPE Skid, Sch 80 PVC Plumbing	2 x 100% Metering pumps (plus shelf spare) 1.2 gph 0.5 HP each
VSEP Sodium Bisulfite Feed System	Tote Fed 40% Active	HDPE Skid, Sch 80 PVC Plumbing	2 x 100% Metering pumps (plus shelf spare) 2 gph 0.5 HP each
VSEP Antiscalant 2 System	Tote Fed 100% Active	HDPE Skid, Sch 80 PVC Plumbing	2 x 100% Metering pumps (plus shelf spare) 1 gph 0.5 HP each
Spiral RO Antiscalant 2 System	Tote Fed	HDPE Skid, Sch 80 PVC Plumbing	2 x 100% Metering pumps (plus shelf spare) 1 gph 0.5 HP each
Biocide Feed System	Tote Fed	HDPE Skid, Sch 80 PVC Plumbing	2 x 100% Metering pumps (plus shelf spare) 1 gph 1 HP each
Stage 1 Low Pressure VSEP Low pH Membrane Cleaner (NLR 404) Feed System	See NLR 404 Storage Tank	Varies	4 x 100% Metering pumps 1 HP each
Stage 1 Low Pressure VSEP CIP High pH Membrane Cleaner (NLR 505) Feed System	See NLR 505 Storage Tank	Varies	4 x 100% Metering pumps 1 HP each

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Item	Description	Materials	Size
Stage 2 High Pressure VSEP CIP Low pH Membrane Cleaner (NLR 404) Feed System	See NLR 404 Storage Tank	Varies	2 x 100% Metering pumps 1 HP each
Stage 2 High Pressure VSEP CIP High pH Membrane Cleaner (NLR 505) Feed System	See NLR 505 Storage Tank	Varies	2 x 100% Metering pumps 1 HP each
Stage 3-5 Spiral RO CIP Low pH Membrane Cleaner (NLR 404) Feed System	See NLR 404 Storage Tank	Varies	1 x 100% Metering pumps 1 HP each
Stage 3-5 Spiral RO CIP High pH Membrane Cleaner (NLR 505) Feed System	See NLR 505 Storage Tank	Varies	1 x 100% Metering pumps 1 HP each
NLR 404 Storage Tank	Cylindrical Closed Top Chemical Storage Tank	HDPE	1 x 100% 4000 gal
NLR 505 Storage Tank	Cylindrical Closed Top Chemical Storage Tank	HDPE	1 x 100% 4000 gal
AVARA Acid Feed System	Tote Fed		2 x 100% Metering pumps (plus shelf spare) 1 gph 1 HP each
AVARA Antiscalant Feed System	Tote Fed		2 x 100% Metering pumps (plus shelf spare) pumps 1 gph 0.5 HP each

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Level 1 Schedule

[Attached separately until final draft]

Major Equipment Lead Times

Table 10. Major Equipment Lead Times

Major Equipment Lead Times	
Vendor (Equipment)	**Lead Time**
New Logic (Membranes)	24 months
AVARA (Evaporators)	16 months
Batch Plant (By Others)	30 weeks

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VSEP & AVARA Equipment Descriptions

Item A – VSEP Membranes and Spiral RO Membrane Systems

Table 11. New Logic VSEP and Spiral RO Membrane System Design Overview

System Design Overview

Parameter	Value
Influent Flow Rate	1500 gpm
Estimated System Filtrate Recovery	~69%
Stage 1 LP VSEP Recovery	~50%
Stage 2 HP VSEP Recovery	~50%
Stage 3 SRO Recovery	~78%
Stage 4 SRO Recovery	~82%
Stage 5 SRO Recovery	~85%

Design Assumptions:

Design Case 1:

The VSEP Stage 1 modules are designed for a total flow rate of 1867 gpm. This includes 1500 gpm of phys/chem effluent and 367 gpm of recycled reject from the Stage 3 Spiral RO Membranes and an influent TDS value of 10,000 mg/L. A membrane efficiency factor of 130% is applied to the design flux to reflect the change in membrane throughput over time. This factor would correlate to 100% throughput effectiveness in year three of operation.

Redundancy and cleaning frequency is estimated on a per day basis at roughly 8% of an operational day. It is important to note that this is not the actual cleaning/maintenance frequency and is an average assumed value.

VSEP Stage 1 Low Pressure Membranes Specifications

Filter Pack:

Membrane:	RO
Allowable Process Temperature:	5°C-60°C
Allowable Feed Slurry pH Range:	2-12
O-ring and Seal Material:	EPDM
Filter Pack Housing:	Glass impregnated epoxy resin (FRP)
Wetted Steel Trays:	304 Stainless Steel
Wetted Plastic End Plates:	Polypropylene

Vibration System:

Vibration Drive Motor:	Baldor CM4106T 460VAC, 3phase, 20HP, 3525 RPM
Motor Speed Controller:	Danfoss 380-480 VAC NEMA 4 (or equal)
Max. Vibration Amplitude:	3/4 inch (peak to peak measured at the Filter Pack)
Frequency Range:	49.0 Hz to 55.0 Hz (Approximate)

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Maximum Decibels:	<85
Bearing RPM:	2800 to 3100
Bearing Oil:	Sullube ~750 ml Compressor Oil
Bearing O-rings:	2-263 & 2-270 Buna

Pump Specifications:

Feed Pump Type:	Grundfos 316SS Vertical Multi-stage Centrifugal
Feed Pump Motor:	Grundfos ML 3500 rpm TEFC 460VAC, 3phase
Motor Speed Controller:	Danfoss 380-480 VAC NEMA 4 (or equal)
Chemical Metering Pump:	Bran+Luebbe
Metering Pump Motor:	Baldor 3/4HP TEFC 120/220V, 1phase, 15A, 60/50Hz

Pre-Screen Basket Strainer:

Filter Housing Type:	NLR Custom Made 316 SS
Basket Strainer:	100 Mesh 316 SS (Considered consumable)
Capacity:	120 GPM
Elastomers (Seals):	EPDM

Operating Site Conditions:

Equipment Rating:	NEMA 4, Indoor/Outdoor protect from sunlight & rain.
Ambient Temperature:	5º - 37°C
Storage Temperature:	2º - 70°C (Protect Filter Pack from Freezing)
Max Relative Humidity:	<95%, non-condensing
Elevation:	3300 ft maximum without derating VFD

Piping:

High Pressure Piping:	Schedule 80 316 SS
Low Pressure Piping:	Schedule 40 316 SS
Special VSEP Concentrate Pipe:	1-1/4” OD 904L Stainless Steel Tubing .065 wall
Flexible Hoses:	SBR/NBR Lined Reinforced Flex Hose
Pipe Clamps:	Zero-Flex Victaulic Style 07 EPDM
On/Off Valves:	316 SS 3-piece ball valve
Manual Valves:	316 SS 3-piece ball valve
Flow Control Valves:	316 SS V-port ball valve
Check Valves:	316 SS swing check valve
Pneumatic Actuators:	Alpha Compact 4, Spring Return
Positioners:	BLX Linear Quarter Turn I/P
Skid Pipe Terminations:	150 lb 316 SS Raised Face Flange
Flange Gaskets:	150 lb Garlock Blue Guard

Clean in Place (CIP):

CIP Pump Type:	Grundfos 316 SS Vertical Multi-Stage Centrifugal
CIP Pump Motor:	Grundfos ML 3500 rpm TEFC 460 VAC 3-phase
Motor Speed Controller:	Danfoss 380-480 VAC NEMA 4 (or equal)
Clean in Place Tank:	200 Gallon Cross Linked Polypropylene
pH Meter:	GF Signet 3-2726-00, 3-2750-1, 3-9900-1
Level Sensor:	IFM Efector PN-2298

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Electrical Specifications:

Controls Voltage:	220/120VAC, 1phase, 15A, 50/60Hz
Enclosures:	Hoffman NEMA 4 Powdercoat Finish
Switches, Relays, & Contactors:	Allen Bradley 220/110 Volt
Programmable Controller:	AB ControlLogix 1756
Operator Display:	AB Industrial Computer
Pressure Sensors:	IFM Efector PN-2292
Mag Flow Tube and Transmitter:	IFM Efector SM2004, SM0540
Bag Filter DP Sensors:	IFM Efector PN-2294
Temperature Sensor:	IFM Efector TN-2511, UT0028
Conductivity Meter:	GF Signet 3-2850-52-42/41
Solenoid Valves:	Festo Manifold Gang Mounted Dual 3/2 24 VDC
CIP Communication:	Festo Ethernet Flex IO
VFD Communication:	Ethernet Com Card
DCS Communication:	Ethernet OPC Server (option for Modbus)

VSEP Stage 2 High Pressure Membranes Specifications

Filter Pack:

Membrane:	RO
Allowable Process Temperature:	5º-60ºC
Max Process Pressure:	1000 psi (7000 kPa)
Allowable Feed Slurry pH Range:	2-12
O-ring and Seal Material:	EPDM (option for Viton)
Filter Pack Housing:	Glass impregnated epoxy resin (FRP)
Wetted Steel Trays:	316 Stainless Steel
Wetted Plastic End Plates:	Polypropylene

Vibration System:

Vibration Drive Motor:	Baldor 380-480VAC, 3phase, 20HP, 3525 RPM Motor
Speed Controller:	Danfoss 20HP 380-480VAC, NEMA 4 (or Equal) Max.
Vibration Amplitude:	3/4 inch (peak to peak measured at the Filter Pack)
Frequency Range:	43.0 Hz to 55.0 Hz (Approximate)
Maximum Decibels:	<85
Bearing RPM:	2800 to 3100
Bearing Oil:	Sullube ~750 ml Compressor Oil
Bearing O-rings:	2-263 & 2-270 Buna

Pump Specifications:

Feed Pump Type:	Hydracell Hastelloy, Horizontal Teflon Diaphragm
Feed Pump Motor:	Baldor 380-480VAC, 3phase, 30HP, 1200 RPM
Booster Transfer Pump Type:	NOTE Supplied by Customer at Feed Tank (24 ft NPSH)
Motor Speed Controller:	Danfoss 380-480VAC, NEMA 4 (or Equal)
Chemical Metering Pump:	Bran+Luebbe Diaphragm pump with manual stroke
Metering Pump Motor:	Baldor 3/4HP TEFC 120/220V, 1phase, 15A, 60/50Hz
Dosing Solenoid Pump:	Chemtech Series 100

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Pre-Screen Basket Strainer:

Filter Housing Type:	NLR Custom Made 2507 Alloy Shell
Basket Strainer:	100 Mesh 316 SS (Considered Consumable)
Capacity:	120 GPM, 4.6 sq ft
Elastomer Seals:	EPDM (option for Viton)

Operating Site Conditions:

Equipment Rating:	NEMA 4, Indoor/Outdoor protect from sunlight & rain.
Ambient Temperature:	5º - 37°C
Storage Temperature:	2º - 70°C (Protect Filter Pack from Freezing)
Max Relative Humidity:	<95%, non-condensing
Elevation:	3300 ft maximum without derating VFD

Piping:

Maximum Pressure:	900 psi
Feed/Concentrate Pressure Piping:	Schedule 80 Super Duplex 2507
Permeate Piping:	Schedule 40 316 SS
Special VSEP Concentrate Pipe:	1-1/4” OD Alloy 20 Stainless Steel .065 wall
Flexible Hoses:	Neoprene Lined Reinforced Weatherhead Flex Hose
Pipe Clamps:	Victaulic Zero-Flex Style 07 EPDM
Pneumatic Air Supply:	90lb Instrument Grade Air (3/8" connection)
Airline Tubing Fittings	Hylok 316 SS
Piping Drain Fittings	Hylok 2507 Duplex
Feed/Conc On/Off Valves	Flotite Alloy 2507 3-piece ball valve
Permeate On/Off Valves	Flotite 316 SS 3-piece ball valve
Flow Control Valves	Flotite Alloy 2507 V-port ball valve
Permeate Check Valves	316 SS Swing check
Pneumatic Actuators	Habonim Compact, Spring Return
Feed/Concentrate Pipe Terminations	150 lb Alloy 2507 Flange
Permeate Pipe Terminations	150 lb 316 SS Flange
Flange Gaskets	150 lb Garlock Blue Guard
Flange Gaskets:	150 lb Garlock Blue Guard

CIP:

CIP Pump Type:	Grundfos 316SS Vertical Multi-stage Centrifugal
CIP Pump Motor:	Grundfos ML 3500 rpm TEFC 460VAC, 3phase
Motor Speed Controller:	AC Tech 380-480VAC, NEMA 4 (or Equal)
Clean in Place Tank:	200 Gallon Sloped Cross Linked Polypropylene
pH Meter:	GF Signet 3-2726-00, 3-2750-1, 3-9900-1
Level Sensors:	IFM Efector PN-2298

Electrical:

Controls Voltage:	120/220VAC, 1phase, 15A, 50/60Hz
Enclosures:	Hoffman NEMA 4 Powdercoat Finish
Wireway Gutters:	Hoffman NEMA 4 Powdercoat Finish
Switches, Relays, & Contactors:	Allen Bradley 120/220 Volt
Remote Access:	Ewon Cosy 131
Programmable Controller:	AB Compact Logix 1769

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Operator Display:	AB Versa View 5400
IO Link Masters and Hubs:	IFM Efector AL1122
Feed/Conc Pressure Sensors	IFM Efector PN-2292 (with 2507ss seals)
Permeate Pressure Sensors	IFM Efector PN-2292 316ss
Conc Mag Flow Tube and Transmitter	Rosemount (or equal) (with Hastelloy electrodes/flanges)
Perm Mag Flow Tube and Transmitter	IFM Efector SM2000 316ss
Bag Filter DP Sensors	Efector PN-2294 (with 2507ss seals)
Temperature Sensor	IFM Efector TN-2511, (with 2507ss thermowell)
Conductivity Meter	Rosemount or equal (PEEK, Hastelloy, EPDM)
pH Meter	Rosemount or equal (PEEK, glass, Hastelloy, EPDM)
Solenoid Valves:	Festo Manifold Gang Mounted Dual 3/2 24 VDC, IO Link
CIP Communication:	IFM Efector IO Link Masters over Ethernet
VFD Communication:	Ethernet Com Card (Ethernet Switch)
DCS Communication:	Ethernet OPC Server (option for Modbus)

Spiral RO Stages 3 – 5 Membranes (S-18000) Specifications

Filter Pack:

Membrane:	RO (depends on application and pilot testing)
Membrane Surface Area:	18000sf (1672m2) (45ea 8”Dia x 40”L)
Maximum Operating Temperature:	120 ^{O}F (49ºC) (Options for up to 80ºC)
Allowable Feed Slurry pH Range:	2-11
O-ring Material:	Ethylene Propylene
Filter Pack Housing:	Polyurethane Coated, Filament Wound, Epoxy
FRP Wetted Ports:	316L Stainless Steel
Wetted Plastic End Plates:	PVC Thermoplastic

Piping:

Maximum Pressure:	550 psi (Options for up to 1200
psi) Pressure Piping:	316L Stainless Steel Schedule 80
Atmospheric Piping:	316L Stainless Steel Schedule 40
Pipe Clamps:	Zero-Flex Victaulic Style 07
EPDM On/Off Valves:	316 SS 3-piece ball valve
Flow Control Valves:	316 SS V-port ball valve
Check Valves:	316 SS swing check valve
Pneumatic Actuators:	Habonim Compact, Spring Return
Positioners:	BLX Linear Quarter Turn I/P
Skid Pipe Terminations:	150 lb 316 SS Raised Face Flange
Flange Gaskets:	150 lb Garlock Blue Guard

Pump Specifications:

Feed Pump Type:	Grundfos 316SS Vertical Multi-stage
Centrifugal Feed Pump Motor:	Grundfos ML 3500 rpm TEFC 460VAC, 3phase
Motor Speed Controller:	Danfoss 380-480VAC, NEMA 4 (or Equal)

Pre-Screen Basket Strainer:

Filter Housing Type:	NLR Custom Made 316 SS
Basket Strainer:	100 Messh 316SS (Optional Felt Bag Filter)
Capacity:	120 GPM, 4.6 sq ft
Elastomer Seals:	EPDM (option for Viton)

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Operating Site Conditions:

Equipment Rating:	NEMA 4, Indoor/Outdoor protect from sun & rain.
Ambient Temperature:	5 - 37°C
Storage Temperature:	2 - 70°C (Project Filter Pack from Freezing)
Max Relative Humidity:	<95%, non-condensing
Elevation:	3300 ft maximum without derating

Electrical Specifications:

(Note typically this is provided with a VSEP system, and the PLC/HMI is split with the spiral system. The controls are mounted on CIP 'Clean in Place' Skid that is also shared)

Controls Voltage:	120/220VAC, 1phase, 15A,5 0/60Hz
Programmable Controller Type:	None (Control signals from CIP PLC)
Touch Screen Display Type:	None (Set Point change at CIP HMI)
Enclosures:	*Hoffman* NEMA 4 Powdercoat Finish 20x16x8
Switches, Relays, & Contactors:	Allen Bradley 120/220 Volt
IO Link Masters and Hubs:	IFM Efector AL1122
Pressure Sensors:	IFM Efector PN-2292
Mag Flow Tube and Transmitter:	IFM Efector SM2000, SM8000
Bag Filter DP Sensors:	IFM Efector PN-2294
Temperature Sensor:	IFM Efector TN-2511, UT0028
Conductivity Meter:	IFM Efector LDL-100
Solenoid Valves:	Festo Manifold Gang Mounted Dual 3/2 24 VDC, IO Link
VSEP and CIP Communication:	IO Link
VFD Communication:	Ethernet Com Card
DCS Communication:	Ethernet OPC Server (option for Modbus)

Item B – AVARA: Advanced Vapor Recompression System

Table 12. Advanced Vapor Recompression System (AVARA) System Design Overview

System Design Overview

Parameter	Value
Total Influent Flow Rate	467 gpm
Total Estimated Evaporation	383 gpm
Total Estimated Brine	84 gpm
Feed TDS	45,000 ppm
Target Brine TDS	250,000 ppm
Nominal Operating Electricity	7910 kW
Required Electricity	480V / 3 Phase / 60 hz

AVARA features patented submerged core technology. Feed water is pumped into a tank and heated with immersion heaters. As steam is generated, compressors force the steam back into the submerged heat exchanger (core) where the steam recondenses into a clean distillate. The AVARA is capable of concentrating the residual brine in the tank up to 300,000 ppm TDS before being discharged from the system for disposal or beneficial use. AVARA can significantly reduce the amount of wastewater requiring disposal while providing a distilled water byproduct.

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AVARA Specifications

Table 13. AVARA System Design Specifications (per Treatment Unit)

AVARA System Specifications (per Treatment Unit)	
Parameter	**Value**
Skid Dimension	12’ W x 50’ L x 10’ H
Skid Shipping Weight	100,000 lbs
Weather Enclosed	Yes
Fuel Type	Electricity: Grid or Genset
Line Power	3 Phase – 480V; 800 Service Amps; 500 Running Amps
Generated Power	Min. 450kW Genset (prime rated)
Volume Capacities	Mid-range to high TDS feed
Discharge TDS	Up to 300,000+ PPM TDS
Inlet Water Pressure	5’ Head Pressure
Set-up Time	24 Hours
Remote Monitoring	Yes

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Solidification Equipment Descriptions

Item A – Standley Batch Systems, Inc.

Table 14. Encapsulation Standley Batch Systems Fly Ash Silo Overview

Item No.	Description
1A	Flyash Silo (1850 cuft)
1B	Flyash Silo (1850 cuft)
2A	Flyash Silo (1850 cuft)
2B	Flyash Silo (1850 cuft)
3A	Flyash Silo (1850 cuft)
3B	Flyash Silo (1850 cuft)
3C	Lime Silo (1600 cuft)
4	HyControl Silo Safety (7 Silo)
5	Screw Conveyors (2)
6	Weigh Batcher
7	Water Tank and Weigh Batcher
8	Drive Thru Structure
9	Collecting Hopper
10	Valve Bank Enclosure
11	Starter Enclosure

Item B – C&W DusTech

Table 15. C&W DusTech System Overview

Item No.	Description
12	Dust Collector w/ Explosion Protection
13	Flap Valve Package
14	Drive Up Truck Dust Shroud
15	Ductwork Package (Shroud)
16	Ductwork Package (Silos)
17	Weigh Batcher Dust Collector
18	Mounting Flange-Weigh Batcher

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Item C – Command Alkon

Table 16. Command Alkon System Overview

Item No.	Description
19	Freight
20	Water Scale
21	Command Batch CP Control
22	Continuous Bin Levels
23	Installation
24	Travel
25	Project Management
26	Airfare
27	Expenses

Item D – BinMaster Inventory Management

Table 17. BinMaster Inventory Management Overview

Item No.	Description
28	Continuous Measurement System (7 silo)
29	Mounting Plates (7)
30	Bin Disc Interface
31	Data Cable
32	On-site Startup

Item E – Solidification Site Work and Installation

Table 18. Solidification Site Work and Installation Services Overview

Item No.	Description
33	Foundations, Ramps, Dust Collector Pads, Piers, Curbs
34	Installation and Erection

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Engineering & Design Services

Scope of Services

Deliverables developed during the engineering and design phase will serve as the basis of design for the project. The following engineering tasks and deliverables are included in this bid:

- Design Criteria
- Process Flow Diagram
- Process & Instrumentation Diagrams
- Mass Balance
- Hydraulic Profile
- Equipment Descriptions (GA drawings & Datasheets)
- Control Narrative
- Equipment Layout
- 3D Plant Modeling
- Site Civil Design
- HVAC Design
- Design & Construction Schedule

Process Flow Diagram (PFD)

WesTech offers a wide range of treatment equipment that can be implemented in multiple process configurations and we will refine the approach with input from the finalized Design Criteria.

The PFD will identify the major pieces of equipment, their position in the process and the main control loops operating the process. They will indicate the main process streams and utility lines.

Deliverable:

- Process Flow Diagram

Process & Instrumentation Diagrams (P&IDs)

After the Process Flow Diagram is finalized, WesTech will develop preliminary P&IDs for the process. The P&IDs will portray the components needed to run, monitor, control specific processes and will depict their relationship with each other. P&IDs will show equipment, piping that connects the equipment, instrumentation, and valves. The information compiled in the P&ID will provide the blueprint for the system and set the scope of the final project, define the process parameters and the level of controls. The P&IDs and supporting documentation are the most important document when establishing the details of the project.

P&IDs will be generated following ISA S5.1 and the owner's specifications. P&IDs typically include, but are not limited to the following information:

- Equipment names, tag and design conditions
- Relief valve location, tag numbers, sizes and pressure. Relief valve interlocks
- Venting, draining, maintenance, shutdown and start-up requirements are indicated
- Type of manual valves are identified, specialty piping items are tagged, and piping notes are added

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- Control valves size, fail position, tags, and interlocks
- Vessel nozzles, details, and levels
- Process and utility lines
- Line sizes, line numbers, pipe specifications and product designation are indicated
- All instrumentation is shown with alarm and switch set points
- Instrument signals to control system are detailed
- Scope of supply, system boundaries

Deliverable:

- P&IDs based on finalized PFD

Mass Balance

WesTech will perform mass balance calculations based on the finalized Design Criteria and PFD. Mass balance values will be used as inputs for specific equipment sizing.

Deliverable:

- Mass Balance calculations based on finalized PFD

Equipment Descriptions (General Arrangement Drawings & Datasheets)

WesTech will provide detailed equipment descriptions including General Arrangement (GA) drawings, equipment datasheets, and other lists as required.

Deliverables:

- Equipment datasheets
- GA drawings

Hydraulic Profile

WesTech will perform hydraulic calculations for the treatment system within the specified boundaries given in the Battery Limits Table of the Design Basis.

Deliverables:

- Hydraulic profile drawing

HAZOP Assistance

WesTech will provide personnel for one (1) trip up to five (5) working days to participate in a hazard and operability study (HAZOP) workshop that will be conducted by others. Our process and controls engineers will assist in identifying and evaluating potential risks to personnel or equipment and operability issues.

Control Narrative

WesTech process engineers will provide control narratives in paragraph form describing functionality of each unit process. Descriptions will include an overall description of the piece of equipment and how it is operated via pumps, blowers, valves, instruments, control logic, etc. Descriptions will also outline interactions between individual unit processes. The control narrative will provide the basis for PLC logic programming.

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Equipment Layout

As the equipment manufacturer, WesTech is intimately familiar with the plant site layout requirements needed to produce a functional site plan. Our in-house former mechanical piping contractors are experts at laying out piping networks to connect all the plant components. We use 3D modeling software to further increase our accuracy with interconnecting piping and civil structures.

Deliverable:

- Equipment layout drawings in native AutoCAD

3D Plant Modeling

- Equipment and interconnecting piping model
- Provided in native AutoCAD Plant 3D
- Periodic updates viewable in NavisWorks

Deliverables:

- 50% Model Review Workshop
- 90% Model Review Workshop

Site Civil Design

- Site survey & topography
- Geotechnical investigation
- Finish grading plan design
- Storm drainage design
- Access road design
- Footing and foundation design

HVAC Design

- Area classification identifications
- Heat load calculations
- Ventilation fan and louver sizing
- Unit heater equipment selection, and location drawings
- Make-up air unit sizing and ducting design drawings
- Mechanical cooling unit equipment selection and location drawings

Design & Construction Schedule

WesTech will develop a detailed design and construction schedule that will be used by the team to ensure resources are properly allocated and to identify critical path items. The schedule will be a detailed Gantt chart using the latest Primavera P6 software to outline design, construction and start-up milestones.

Deliverable:

- Initial detailed design & construction Gantt chart schedule

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Clarifications and Exceptions

This report is provided as a non-binding budgetary study. The scope included does not reflect WesTech's intended scope of work if this project were to be actualized.

General Clarifications

Terms & Conditions: Changes to any terms and conditions, including but not limited to submittal and shipment days, payment terms, and escalation clause shall be negotiated at order placement, otherwise the proposal terms and conditions contained herein shall apply.

Paint: If your equipment has paint included in the price, please take note to the following. Primer paints are designed to provide only a minimal protection from the time of application (usually for a period not to exceed 30 days). Therefore, it is imperative that the finish coat be applied within 30 days of shipment on all shop primed surfaces. Without the protection of the final coatings, primer degradation may occur after this period, which in turn may require renewed surface preparation and coating. If it is impractical or impossible to coat primed surfaces within the suggested time frame, WesTech strongly recommends the supply of bare metal, with surface preparation and coating performed in the field. All field surface preparation, field paint, touch-up, and repair to shop painted surfaces are not by WesTech.

Escalation: If between the proposal date and actual procurement and through no fault of the Seller, the relevant cost of labor, material, freight, tariffs, and other Seller costs combined relating to the contract, increase by greater than 2.5% of the overall contract price, then the contract price shall be subject to escalation and increased. Such increase shall be verified by documentation and the amount of contract price escalation shall be calculated as either the actual increased cost to the Seller or, if agreed by the Parties, the equivalent increase of a relevant industry recognized third-party index, and in both cases without any additional profit or margin being added.

USA Tariffs and Current Trade Laws: All prices are based on current USA and North America tariffs and trade laws/agreements at time of bid. Any changes in costs due to USA Tariffs and trade laws/ agreements will be passed through to the purchaser at cost.

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Commercial Proposal

Proposal Name: Plant Bowen Budgetary Study
Proposal Number: 24926A
Thursday, May 25, 2023

1. Bidder's Contact Information

Company Name	WesTech Engineering LLC
Primary Contact Name	Dallas Torgersen
Phone	801.265.1000
Email	DTorgersen@westech-inc.com
Address: Number/Street	3665 S West Temple
Address: City, State, Zip	Salt Lake City, UT 84115

2. Budget Pricing

Currency: US Dollars

Scope of Supply

A	Engineering	$16,500,000
B	Procurement	$156,000,000
C	Freight	$1,200,000
D	Construction	$83,500,000
E	Commissioning & Start-up	$6,000,000
F	Solidification Equipment	$29,428,000
G	Solidification Site Work and Installation	$11,956,000
Process Island Cost		**$304,584,000**
	Taxes (sales, use, VAT, IVA, IGV, duties, import fees, etc.)	Not Included

Prices are valid for a period not to exceed 30 days from date of proposal.

Additional Field Service

Daily Rate (Applicable Only to Field Service Not Included in Scope)	$1,450

Pricing does not include field service unless noted in scope of supply, but is available at the daily rate plus expenses. The greater of a two week notice or visa procurement time is required prior to departure date. Our field service policy can be provided upon request for more details.

4. Schedule

Please refer to Level 1 Schedule Section

5. Freight

Domestic		FOB Shipping Point - Prepaid and Added (FSP-PPA)
From	**Final Destination**	**Number of Trucks or Containers**
WesTech Shops	Euharlee, GA	TBD

The Process Island Cost provided includes only the costs associated with WesTech's discrete scope of work, as outlined in this budgetary study. A "Total Project Cost" estimate (including but not limited to such costs as work by the plant, project management, insurance, etc.) will likely be generated by Georgia Power Company and/or Southern Company Services and would represent the comprehensive dollar figure associated with the installation of the new treatment system at Plant Bowen.

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One-Year Warranty

WesTech is meeting a global need for clean water through technology treatment solutions. We are proud that the equipment and systems we design, build, maintain, and operate are making the world a better place and creating a more sustainable environment for future generations.

Equipment manufactured or sold by WesTech Engineering, LLC, once paid for in full, is backed by the following warranty:

Subject to the terms below, WesTech warrants all new equipment manufactured or sold by WesTech Engineering, LLC to be unencumbered and free from defects in material and workmanship, and WesTech will replace or repair, F.O.B. its factories or other location it chooses, any part or parts returned to WesTech which WesTech's examination and analysis determine have failed within the warranty period because of defects in material and workmanship. The warranty period is either, one calendar year immediately following start-up, or eighteen (18) months from when WesTech sent its ready-to-ship notification to the purchaser, whichever expires sooner. All repair or replacement parts qualifying under this warranty shall be free of charge. Purchaser will provide timely written notice to WesTech of any defects it believes should be repaired or replaced under this warranty. WesTech will reject as untimely any warranty defect claim that purchaser submits more than thirty (30) days after the possible warranty defect first occurred. Unless specifically stated otherwise, this warranty does not cover normal wear or consumables. This warranty is not transferable.
This warranty shall be void and shall not apply where the equipment or any part thereof

(a) has been dismantled, modified, repaired or connected to other equipment, outside of a WesTech factory, or without WesTech's written approval, or

(b) has not been installed in complete adherence to all WesTech's or parts manufacturer's requirements, recommendations, and procedures, or

(c) has been subject to misuse, abuse, neglect, or accident, or has not at all times been operated and maintained in strict compliance with all of WesTech's requirements and recommendations therefor, including, but not limited to, the relevant WesTech Operations & Maintenance Manual and any other of WesTech's specified guidelines & procedures, or

(d) has been subject to force majeure events; use of chemicals not approved in writing by WesTech; electrical surges; overloading; significant power, water or feed supply fluctuations; or non-compliance with agreed feedwater or chemical volumes, specifications or procedures.

In any case where a part or component of equipment under this warranty is or may be faulty and the component or part is also covered under the warranty of a third party then the purchaser shall provide reasonable assistance to first pursue a claim under the third-party warranty before making a claim under this warranty from WesTech. WesTech Engineering, LLC gives no warranty with respect to parts, accessories, or components purchased other than through WesTech. The warranties which apply to such items are those offered by the respective manufacturers.

This warranty is expressly given by WesTech and accepted by purchaser in lieu of all other warranties whether written, oral, express, implied, statutory or otherwise, including without limitation, warranties of merchantability and fitness for particular purpose. WesTech neither accepts nor authorizes any other

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person to assume for it any other liability with respect to its equipment. WesTech shall not be liable for normal wear and tear, corrosion, or any contingent, incidental, or consequential damage or expense due to partial or complete inoperability of its equipment for any reason whatsoever. The purchaser's exclusive and only remedy for breach of this warranty shall be the repair and or replacement of the defective part or parts within a reasonable time of WesTech's accepting the validity of a warranty claim made by the purchaser.

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Terms & Conditions

Terms and Conditions appearing in any order based on this proposal which are inconsistent herewith shall not be binding on WesTech Engineering LLC The sale and purchase of equipment described herein shall be governed exclusively by the foregoing proposal and the following provisions:

1. SPECIFICATIONS: WesTech Engineering LLC is furnishing its standard equipment as outlined in the proposal and as will be covered by final approved drawings. The equipment may not be in strict compliance with the Engineer's/Owner's plans, specifications, or addenda as there may be deviations. The equipment will, however, meet the general intention of the mechanical specifications of these documents.

2. ITEMS INCLUDED: This proposal includes only the equipment specified herein and does not include erection, installation, accessories, nor associated materials such as controls, piping, etc., unless specifically listed.

3. PARTIES TO CONTRACT: WesTech Engineering LLC is not a party to or bound by the terms of any contract between WesTech Engineering LLC's customer and any other party. WesTech Engineering LLC's undertakings are limited to those defined in the contract between WesTech Engineering LLC and its direct customers.

4. PRICE AND DELIVERY: All selling prices quoted are subject to change without notice after 30 days from the date of this proposal unless specified otherwise. Unless otherwise stated, all prices are F.O.B. WesTech Engineering LLC or its supplier's shipping points. All claims for damage, delay or shortage arising from such equipment shall be made by Purchaser directly against the carrier. When shipments are quoted F.O.B. job site or other designation, Purchaser shall inspect the equipment shipped, notifying WesTech Engineering LLC of any damage or shortage within forty-eight hours of receipt, and failure to so notify WesTech Engineering LLC shall constitute acceptance by Purchaser, relieving WesTech Engineering LLC of any liability for shipping damages or shortages.

5. PAYMENTS: All invoices are net 30 days. Delinquencies are subject to a 1.5 percent service charge per month or the maximum permitted by law, whichever is less on all past due accounts. Pro rata payments are due as shipments are made. If shipments are delayed by the Purchaser, invoices shall be sent on the date when WesTech Engineering LLC is prepared to make shipment and payment shall become due under standard invoicing terms. If the work to be performed hereunder is delayed by the Purchaser, payments shall be based on the purchase price and percentage of completion. Products held for the Purchaser shall be at the risk and expense of the Purchaser. Unless specifically stated otherwise, prices quoted are for equipment only. These terms are independent of and not contingent upon the time and manner in which the Purchaser receives payment from the owner.

6. PAYMENT TERMS: Credit is subject to acceptance by WesTech Engineering LLC's Credit Department. If the financial condition of the Purchaser at any time is such as to give WesTech Engineering LLC, in its judgment, doubt concerning the Purchaser's ability to pay, WesTech Engineering LLC may require full or partial payment in advance or may suspend any further deliveries or continuance of the work to be performed by the WesTech Engineering LLC until such payment has been received.

7. ESCALATION: If shipment is, for any reason, deferred by the Purchaser beyond the normal shipment date, or if material price increases are greater than 5% from proposal date to material procurement date, stated prices set forth herein are subject to escalation. The escalation shall be based upon increases in labor and material and other costs to WesTech Engineering LLC that occur in the time period between quotation and shipment by WesTech Engineering LLC Purchaser agrees to this potential escalation regardless of contradicting terms in the contract, except when an agreed upon escalation adder is included in the price.

(a) The total quoted revised price is based upon changes in the indices published by the United States Department of Labor, Bureau of Labor Statistics. Labor will be related to the Average Hourly Earnings indices found in the Employment and Earnings publication. Material will be related to the Metal and Metal Products Indices published in Wholesale Prices and Prices Indices.

(b) Price revision for items furnished to, and not manufactured by WesTech Engineering LLC, which exceed the above escalation calculation, will be passed along by WesTech Engineering LLC to Purchaser based upon the actual increase in price to WesTech Engineering LLC for the period from the date of quotation to the date of shipment by WesTech Engineering LLC Any item that is so revised will be excluded from the index escalation calculations set forth in subparagraph (a) above.

8. APPROVAL: If approval of equipment submittals by Purchaser or others is required, a condition precedent to WesTech Engineering LLC supplying any equipment shall be such complete approval.

9. INSTALLATION SUPERVISION: Prices quoted for equipment do not include installation supervision. WesTech Engineering LLC recommends and will, upon request, make available, at WesTech Engineering LLC's then current rate, an experienced installation supervisor to act as the Purchaser's employee and agent to supervise installation of the equipment. Purchaser shall at its sole expense furnish all necessary labor equipment, and materials needed for installation.

Responsibility for proper operation of equipment, if not installed by WesTech Engineering LLC or installed in accordance with WesTech Engineering LLC's instructions, and inspected and accepted in writing by WesTech Engineering LLC, rests entirely with Purchaser; and any work performed by WesTech Engineering LLC personnel in making adjustment or changes must be paid for at WesTech Engineering LLC's then current per diem rates plus living and traveling expenses.

WesTech Engineering LLC will supply the safety devices described in this proposal or shown in WesTech Engineering LLC's drawings furnished as part of this order but excepting these, WesTech Engineering LLC shall not be required to supply or install any safety devices whether required by law or otherwise. The Purchaser hereby agrees to indemnify and hold harmless WesTech Engineering LLC from any claims or losses arising due to alleged or

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actual insufficiency or inadequacy of the safety devices offered or supplied hereunder, whether specified by WesTech Engineering LLC or Purchaser, and from any damage resulting from the use of the equipment supplied hereunder.

10. ACCEPTANCE OF PRODUCTS: Products will be deemed accepted without any claim by Purchaser unless written notice of non-acceptance is received by WesTech Engineering LLC within 30 days of delivery if shipped F.O.B. point of shipment, or 48 hours of delivery if shipped F.O.B. point of destination. Such written notice shall not be considered received by WesTech Engineering LLC unless it is accompanied by all freight bills for said shipment, with Purchaser's notations as to damages, shortages and conditions of equipment, containers, and seals. Non-accepted products are subject to the return policy stated below.

11. TAXES: Any federal, state, or local sales, use or other taxes applicable to this transaction, unless specifically included in the price, shall be for Purchaser's account.

12. TITLE: The equipment specified herein, and any replacements or substitutes therefore shall, regardless of the manner in which affixed to or used in connection with realty, remain the sole and personal property of WesTech Engineering LLC until the full purchase price has been paid. Purchaser agrees to do all things necessary to protect and maintain WesTech Engineering LLC's title and interest in and to such equipment; and upon Purchaser's default, WesTech Engineering LLC may retain as liquidated damages any and all partial payments made and shall be free to enter the premises where such equipment is located and remove the same as its property without prejudice to any further claims on account of damages or loss which WesTech Engineering LLC may suffer from any cause.

13. INSURANCE: From date of shipment until the invoice is paid in full, Purchaser agrees to provide and maintain at its expense, but for WesTech Engineering LLC's benefit, adequate insurance including, but not limited to, builders risk insurance on the equipment against any loss of any nature whatsoever.

14. SHIPMENTS: Any shipment of delivery dates recited represent WesTech Engineering LLC's best estimate but no liability, direct or indirect, is assumed by WesTech Engineering LLC for failure to ship or deliver on such dates.

WesTech Engineering LLC shall have the right to make partial shipments; and invoices covering the same shall be due and payable by Purchaser in accordance with the payment terms thereof. If Purchaser defaults in any payment when due hereunder, WesTech Engineering LLC may, without incurring any liability therefore to Purchaser or Purchaser's customers, declare all payments immediately due and payable with maximum legal interest thereon from due date of said payment, and at its option, stop all further work and shipments until all past due payments have been made, and/or require that any further deliveries be paid for prior to shipment.

If Purchaser requests postponements of shipments, the purchase price shall be due and payable upon notice from WesTech Engineering LLC that the equipment is ready for shipment; and thereafter any storage or other charge WesTech Engineering LLC incurs on account of the equipment shall be for the Purchaser's account.

If delivery is specified at a point other than WesTech Engineering LLC or its supplier's shipping points, and delivery is postponed or prevented by strike, accident, embargo, or other cause beyond WesTech Engineering LLC's reasonable control and occurring at a location other than WesTech Engineering LLC or its supplier's shipping points, WesTech Engineering LLC assumes no liability in delivery delay. If Purchaser refuses such delivery, WesTech Engineering LLC may store the equipment at Purchaser's expense. For all purposes of this agreement such tender of delivery or storage shall constitute delivery.

15. WARRANTY: WESTECH ENGINEERING LLC WARRANTS EQUIPMENT IT SUPPLIES ONLY IN ACCORDANCE WITH THE WARRANTY EXPRESSED IN THE ATTACHED COPY OF "WESTECH WARRANTY" AGAINST DEFECTS IN WORKMANSHIP AND MATERIALS WHICH IS MADE A PART HEREOF. SUCH WARRANTY IN LIEU OF ALL OTHER WARRANTIES, INCLUDING WARRANTIES OF MERCHANTABILITY AND FITNESS FOR PARTICULAR PURPOSE, WHETHER WRITTEN, ORAL, EXPRESSED, IMPLIED OR STATUTORY, WESTECH ENGINEERING LLC SHALL NOT BE LIABLE ANY CONTINGENT, INCIDENTAL, OR CONSEQUENTIAL DAMAGES FOR ANY REASON WHATSOEVER.

16. PATENTS: WesTech Engineering LLC agrees that it will, at its own expense, defend all suits or proceedings instituted against Purchaser and pay any award of damages assessed against it in such suits or proceedings, so far as the same are based on any claim that the said equipment or any part thereof constitutes an infringement of any apparatus patent of the United States issued at the date of this Agreement, provided WesTech Engineering LLC is given prompt notice in writing of the institution or threatened institution of any suit or proceeding and is given full control of the defense, settlement, or compromise of any such action; and Purchaser agrees to give WesTech Engineering LLC needed information, assistance, and authority to enable WesTech Engineering LLC so to do. In the event said equipment is held or conceded to infringe such a patent, WesTech Engineering LLC shall have the right at its sole option and expense to a) modify the equipment to be non-infringing, b) obtain for Purchaser the license to continue using said equipment, or c) accept return of the equipment and refund to the Purchaser the purchase price thereof less a reasonable charge for the use thereof. WesTech Engineering LLC will reimburse Purchaser for actual out-of-pocket expenses, exclusive of legal fees, incurred in preparing such information and rendering such assistance at WesTech Engineering LLC's request. The foregoing states the entire liability of WesTech Engineering LLC, with respect to patent infringement; and except as otherwise agreed to in writing, WesTech Engineering LLC assumes no responsibility for process patent infringement.

17. SURFACE PREPARATION AND PAINTING: If furnished, shop primer paint is intended to serve only as minimal protective finish. WesTech Engineering LLC will not be responsible for the condition of primed or finish painted surfaces after equipment leaves its shops. Purchasers are invited to inspect paint in shops for proper preparation and application prior to shipment. WesTech Engineering LLC assumes no responsibility for field surface preparation or touch-up of shipping damage to paint. Painting of fasteners and other touch-up to painted surfaces will be by Purchaser's painting contractor after mechanism installation.

Motors, gear motors, and other components not manufactured by WesTech Engineering LLC will be painted with that manufacturer's standard paint system. It is WesTech Engineering LLC's intention to ship major steel components as soon as fabricated, often before drive, motors, and other

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manufactured components. Unless Purchaser can ensure that shop primed steel shall be field painted within thirty (30) days after arrival at the job site, WesTech Engineering LLC encourages the Purchaser to order these components without primer.

WesTech Engineering LLC's prices are based on paints and surface preparations as outlined in the main body of this proposal. In the event that an alternate paint system is selected, WesTech Engineering LLC requests that Purchaser's order advise of the paint selection. WesTech Engineering LLC will then either adjust the price as may be necessary to comply or ship the material unpainted if compliance is not possible due to application problems or environmental controls.

18. CANCELLATION, SUSPENSION, OR DELAY: After acceptance by WesTech Engineering LLC, this proposal, or Purchaser's order based on this proposal, shall be a firm agreement and is not subject to cancellation, suspension, or delay except upon payment by Purchaser of appropriate charges which shall include all costs incurred by WesTech Engineering LLC to date of cancellation, suspension, or delay plus a reasonable profit. Additionally, all charges related to storage and/or resumption of work, at WesTech Engineering LLC's plant or elsewhere, shall be for Purchaser's sole account; and all risks incidental to storage shall be assumed by Purchaser.

19. FORCE MAJEURE: Neither party hereto shall be liable to the other for default or delay in delivery caused by extreme weather or other act of God, strike or other labor shortage or disturbance, fire, accident, war or civil disturbance, act of government, pandemic, delay of carriers, failure of normal sources of supply, complete or partial shutdown of plant by reason of inability to attain sufficient raw materials or power, and/or other similar contingency beyond the reasonable control of the respective parties. The time for delivery specified herein shall be extended during the continuance of such conditions, or any other cause beyond such party's reasonable control.

20. RETURN OF PRODUCTS: No products may be returned to WesTech Engineering LLC without WesTech Engineering LLC's prior written permission. Said permission may be withheld by WesTech Engineering LLC at its sole discretion.

21. BACKCHARGES: WesTech Engineering LLC will not approve or accept backcharges for labor, materials, or other costs incurred by Purchaser or others in modification, adjustment, service, or repair of WesTech Engineering LLC-furnished materials unless such back charge has been authorized in advance in writing by a WesTech Engineering LLC employee, by a WesTech Engineering LLC purchase order, or work requisition signed by WesTech Engineering LLC

22. INDEMNIFICATION: Purchaser agrees to indemnify WesTech Engineering LLC from all costs incurred, including but not limited to court costs and reasonable attorney fees, from enforcing any provisions of this contract, including but not limited to breach of contract or costs incurred in collecting monies owed on this contract.

23. ENTIRE AGREEMENT: This proposal expresses the entire agreement between the parties hereto superseding any prior understandings, and is not subject to modification except by a writing signed by an authorized officer of each party.

24. MOTORS AND MOTOR DRIVES: In order to avoid shipment delays of WesTech Engineering LLC equipment, the motor drives may be sent directly to the job site for installation by the equipment installer. Minor fit-up may be required.

25. EXTENDED STORAGE: Extended storage instructions will be part of information provided to shipment. If equipment installation and start-up is delayed more than 30 days, the provisions of the storage instructions must be followed to keep WARRANTY in force.

26. LIABILITY: Professional liability insurance, including but not limited to, errors and omissions insurance, is not included. In any event, liability for errors and omissions shall be limited to the lesser of $100,000USD or the value of the particular piece of equipment (not the value of the entire order) supplied by WesTech Engineering LLC against which a claim is sought.

27. ARBITRATION NEGOTIATION: Any controversy or claim arising out of or relating to the performance of any contract resulting from this proposal or contract issued, or the breach thereof, shall be settled by arbitration in accordance with the Construction Industry Arbitration Rules of the American Arbitration Association, and judgment upon the award rendered by the arbitrator(s) may be entered to any court having jurisdiction.

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EXHIBIT 7

COMMENTS OF THE ELECTRIC POWER RESEARCH INSTITUTE ON

ENVIRONMENTAL PROTECTION AGENCY

Docket ID: EPA–HQ–OW-2009

[EPA–HQ–OW–2009–0819; FRL–10002–04–OW]; RIN 2040-AF77

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

January 20, 2020

The Electric Power Research Institute, Inc. (EPRI) respectfully submits the enclosed comments on the U.S. Environmental Protection Agency's (EPA's) above-referenced proposal. EPRI appreciates the opportunity to comment on this document.

EPRI is a nonprofit corporation organized under the laws of the District of Columbia Nonprofit Corporation Act and recognized as a tax-exempt organization under Section 501(c)(3) of the U.S. Internal Revenue Code of 1986, as amended, and acts in furtherance of its public benefit mission. EPRI was established in 1972 and has principal offices and laboratories located in Palo Alto, Calif.; Charlotte, N.C.; Knoxville, Tenn.; Dallas, Texas; Lenox, Mass.; and Washington, D.C. EPRI conducts research and development relating to the generation, delivery, and use of electricity for the benefit of the public. As an independent, nonprofit organization, EPRI brings together its scientists and engineers, as well as experts from academia and industry, to help address challenges related to electricity, including reliability, efficiency, health, safety, and environmental stewardship. EPRI also provides technology, policy, and economic analyses to inform long-range research and development planning, and supports research in emerging technologies. As a tax-exempt research organization, EPRI makes its research results widely available to the interested public through license, purchase, or other dissemination.

These comments reflect EPRI research experience related to flue gas desulfurization (FGD) wastewater characterization and treatment, as well as bottom ash transport water management. These comments reflect EPRI's research activities in that they are technical rather than legal in nature. The enclosed comments are EPRI's, and do not necessarily reflect the opinions of those supporting and working with EPRI to conduct collaborative research and development. EPRI hopes its comments and technical feedback will be valuable to EPA.

Sincerely,



Robert Chapman
Vice President, Energy and Environment

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EPRI COMMENTS ON PROPOSED EFFLUENT LIMITATIONS GUIDELINES RULE

U.S. Environmental Protection Agency

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

Docket ID: EPA–HQ–OW–2009

40 CFR Part 423

(Federal Register, Volume 84, Number 226, Friday, November 22, 2019; [EPA–HQ–OW–2009–0819; FRL–10002–04-OW]; RIN 2040–AF77)

Submitted by:

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January 20, 2020

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EXECUTIVE SUMMARY

The Electric Power Research Institute (EPRI) was established in 1973 as an independent, nonprofit center for public interest energy and environmental research. EPRI brings together member organizations, the Institute's scientists and engineers, and other leading experts to work collaboratively on solutions to the challenges of electric power. These solutions span nearly every area of power generation, delivery, and use, including health, safety, and environment. EPRI's members represent more than 90 percent of the electricity generated in the United States.

EPRI is providing comments to the U.S Environmental Protection Agency (EPA) on the "Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category," (referred to here as the "proposed revised Effluent Limitations Guidelines [ELG] rule") and on supporting information in docket EPA-HQ-OAR-2009-0819. The proposed revised ELG rule addresses two areas of the 2015 ELG rule—flue gas desulfurization (FGD) wastewater and bottom ash transport water (BATW). EPRI's comments focus on:

- Proposed best available technology (BAT) for FGD wastewater treatment (chemical-precipitation and biological treatment), including capital cost, operating and maintenance costs, and technical feasibility
- Voluntary incentives program (VIP) for FGD wastewater treatment and technical feasibility
- Bromide: downstream impacts
- Bottom ash: the costs and pollutant removals for allowing a purge for operational flexibility and cost-effectiveness, and setting a technology-based limit on the purge
- Pollution reduction benefits of the FGD wastewater and ash BATW limits

In 1996, EPRI initiated an effort to characterize plant wastewaters and to evaluate sampling and analytical techniques for low-level trace metals those wastewaters may contain. More recently, EPRI has conducted numerous studies to clarify mercury and selenium chemistry in FGD wastewaters, to evaluate sampling and analytical methods for trace metals (including selenium speciation) in FGD wastewaters, to evaluate promising technologies for mercury and selenium removal from FGD wastewaters, to evaluate near-real time water quality monitors for FGD wastewaters, and to clarify the factors that impact physical/chemical treatment costs of FGD wastewater. EPRI has also assessed bottom ash handling options, working with more than 20 plants with high-recycle bottom ash systems to understand needed operational flexibility. As a result of these studies, EPRI has significant data and experience which we are providing to EPA as constructive comment on the proposed ELG rule.

EPRI conducted as thorough a review of the proposed rule, the underlying data, and technical support documents as the 60-day comment period would allow. As there were more than 2,000 supporting documents, EPRI was unable to provide a truly comprehensive review; instead, it focused attention and comments on the areas of expertise described above.

Key Comments on FGD BAT Wastewater Treatment Cost

EPA's calculated total annualized cost for treatment of FGD wastewater via chemical precipitation (CP) and biological systems are lower than EPRI's by 70 percent due to a number of factors, including:

- EPA apparently underestimated the peak FGD wastewater design flow used to size equipment. When only average FGD flow was available, EPRI used an adjustment factor, since wastewater treatment equipment must be sized to accommodate the peak flow so that the treatment system can consistently meet limits.
- EPA appears to have underestimated the cost factors that were used to create a total installed cost estimate for each individual plant. EPRI used cost factors more typical of an industry standard engineering estimate.
- EPA appears to have underestimated FGD chemical precipitation equipment redundancy. In order to provide a more accurate cost estimate, EPRI recommends using 2x100% trains for plants with high capacity factors, and 2x60% at plants with lower capacity factors.

Key Comments on the Proposed Numeric BAT Limits for FGD Wastewater

The proposed limits on FGD wastewater may not be achievable for all power plants employing the proposed BAT for the following reasons:

- A number of the selenium and mercury measurements in the EPA datasets used for determining BAT are above both the daily and monthly proposed numeric discharge limits.
- One dataset referenced Analytical Method 200.8, which is not an EPA approved analytical method found in 40 CFR 136 for quantifying low levels of mercury. Method 200.8 would result in low-biased data for mercury due to volatilization. EPA should follow up to confirm that the appropriate method is used.
- Two of the five pilot datasets had unusually low mercury and selenium in untreated FGD water, relative to the broader industry.

Key Comments on FGD VIP Wastewater Treatment Cost

EPA's calculated cost to reach VIP limits for FGD wastewater via membrane and thermal treatment are lower than EPRI's. EPRI's annualized cost estimate for membrane-based treatment with encapsulation is more than 10 times EPA's estimate.

- EPA appears to have underestimated the cost of VIP treatment. EPA's membrane filtration cost curves do not include all of the pretreatment and disposal costs necessary for a complete membrane filtration treatment system.
- Costs for membrane treatment at some plants will be much higher and potentially not economically viable.
- EPA appears to have underestimated FGD wastewater VIP cost relative to the cost of FGD wastewater BAT (chemical precipitation plus biological).
- The thermal evaporation approach to VIP has comparable, if not lower, annualized cost compared to a membrane approach.

Key Comments on FGD VIP Technical Feasibility

The proposed FGD VIP technologies have several significant operational limitations. The proposed limits on treated FGD wastewater under the VIP option may not be achievable for all power plants employing the membrane filtration plus encapsulation approach.

- Pretreatment is critical for attaining/maintaining reliable operation of membrane-based systems and can represent a significant and majority portion of the total cost of a system.
- A challenge in deploying membrane technology is the management of concentrated brine and the solid waste generated by the membrane and pretreatment systems. System design requires balancing clean water (i.e., permeate) recovery, permeate quality, treatment costs, and waste management costs.
- EPA should use the same technology basis to develop membrane treatment costs and numerical effluent limitations. For cost estimating, EPA assumed either no pretreatment or pretreatment using microfiltration only; but in setting limits, EPA used pilot tests that included pretreatment of solids removal (and in some cases, chemical treatment) upstream of membrane treatment.
- Advanced membrane filtration plus encapsulation technologies alone cannot consistently meet the proposed numeric limits.
- The datasets provided for consideration by EPA include data above both the daily maximum and monthly average proposed numeric limits; however, the data used for setting VIP limits are based on limited datasets.
- EPA's rationale for excluding two datasets should be made clear.

Key Comments on Bromide

EPA's bromide mass loading and transport model appears to have overestimated the amount of bromide reaching downstream drinking water treatment systems from current coal-fired power plant discharges. EPA's approach also does not reflect the uncertainties in the scientific understanding of disinfection byproduct formation, exposure, and toxicity.

Key Comments on Bottom Ash Transport Water Proposed BAT Limits

The purge capabilities allowed by the revised ELG would provide operational flexibility, while still providing a large majority of the pollutant reduction that would have been achieved by the 2015 ELGs. Certain issues remain, such as:

- EPA's selection of reverse osmosis (RO) technology for eliminating a purge is technically challenging and overly complex when deploying a fully closed-loop remote bottom ash dewatering system. RO also does not address all sources of purge water that could occur, making a no-discharge solution unworkable.
- Setting limits on bottom ash loop purge based on solids/total suspended solids (TSS) removal provides pollutant reduction levels comparable to those of chemical precipitation, at significantly lower cost.

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2. FGD WASTEWATER BAT TREATMENT COSTS

2.1 EPA underestimated the capital cost of FGD BAT (chemical precipitation plus low residence time reduction biological treatment) for the industry. EPRI's annualized cost estimate is approximately 70 percent higher than EPA's estimate.

EPRI compared EPA's cost estimates for chemical precipitation (CP) and low residence time reduction (LRTR) biological treatment (biological) published in *Generating Unit-Level Costs and Loadings Estimates by Regulatory Option* – DCN SE07090, Table 4 (FGD CP Only) and *Updated Flue Gas Desulfurization Low Residence Time Reduction (LRTR) Cost Methodology*, Appendix 3 (FGD CP + Biological) [ERG, 2019b; 2019d] with its own estimate of the cost to comply with the ELG rule. EPRI updated industry profiles, reflecting changes announced as of October 2018, to match EPA's industry portfolio, as documented in *Changes to Industry Profile for Coal-Fired Generating Units for the Steam Electric Effluent Guidelines Proposed Rule* – DCN SE07207 and *Generating Unit-Level Costs and Loadings Estimates by Regulatory Option* – DCN SE07090, [ERG, 2019a; 2019b] (unless otherwise noted). These updates included new units, new wet FGD systems, coal unit retirements and fuel conversions, and modifications to wet FGD treatment and bottom ash systems. Therefore, the list of units for which EPRI is providing capital and O&M costs is very similar to the list of units EPA has used. Table 2-1 below compares EPA and EPRI chemical precipitation and biological costs.

Table 2-1
Chemical precipitation and biological cost comparison for the industry

	Source of Industry Cost	Capital Cost ($M)	Ratio of EPRI to EPA Capital Cost	Annual O&M Cost ($M/yr)	Total Annualized Cost ($M/yr) @7%	Ratio of EPRI to EPA Annualized Cost
Option 1 (CP Only)	EPA	$675		$42	$105	
	EPRI	$1,652	2.4	$46	$202	1.9
Option 2 (CP + Biological)	EPA	$1,127		$76	$181	
	EPRI	$2,495	2.2	$79	$314	1.7
Incremental Biological *	EPA	$452		$33	$76	
	EPRI	$843	1.4	$27	$107	1.4

Biological = Low Residence Time Reduction (LRTR) biological treatment
CP = Chemical precipitation stand-alone treatment.
M = million
O&M = Operations and maintenance
$ = U.S. dollars, pre-tax in 2018 dollars
Assume 7% interest rate and 20-year life for annualized cost
* EPA's incremental biological costs were calculated by subtracting CP standalone costs for Regulatory Option 1 from ERG's *Generating Unit-Level Costs and Loadings Estimates by Regulatory Option – DCN SE07090* from CP + Biological costs from Appendix 3 of ERG's *Updated Flue Gas Desulfurization Low Residence Time Reduction (LRTR) Cost Methodology*. This does not account for cost differences between EPA's CP stand-alone costs and EPA's CP pretreatment costs.

As one can see from Table 2-1, the factors by which EPRI's estimates exceed EPA's estimate are significant, more so for capital cost estimates that range from 86 percent higher to 144 percent

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higher. The major differences between estimates made by EPA and EPRI include the following, each of which is discussed in more detail in the subsections below:

1. EPA appears to have underestimated the peak FGD wastewater design flow used to size equipment.
2. EPA appears to have underestimated the cost factors used to calculate total installed costs from vendor estimates [EPA, 2019a]. Standard industry practice for developing budgetary cost estimates uses cost factors that are more typical of an engineering estimate; these engineering cost factors should be used.
3. EPA underestimated FGD chemical precipitation equipment redundancy that would be required on this critical equipment.
4. Costs appears to be underestimated at plants with high-salinity FGD water.

The impact of the differences in cost factors used to calculate total installed costs can be seen in Table 2-2, in which we have normalized EPRI and EPA's estimating to assume the same design flow rate of 300 gpm and the same redundancy of 2x60% for FGD chemical precipitation.

Table 2-2
Chemical precipitation and biological cost comparison for a case study plant designed for 300 gpm flow

	EPA	EPRI	EPA	EPRI	EPA	EPRI
	CP Pretreatment, 2x60% redundancy		Incremental Biological		CP + Biological	
Capital Cost ($M)	23	34	9	13	32	47
Annualized Capital Cost ($M/yr) @7%	22	3.2	0.9	1.2	3.0	4.5
Factor of EPRI to EPA Capital Cost		1.5		1.4		1.5

Biological = Low Residence Time Reduction (LRTR) biological treatment. For EPA's cost, EPRI used high-nitrate (the more expensive of the two options). For purposes of this comparison, the EPRI cost also includes nitrate pretreatment.
CP = Chemical precipitation treatment. For EPA's cost, EPRI used offsite transport/disposal of solids. For a 300-gpm case study plant, offsite transport/disposal of solids is about 1 percent more expensive than onsite transport/disposal, so it was selected to show that—even using the more expensive of EPA's two options—EPRI's costs are higher than EPA's.
gpm = gallons per minute
M = million
$ = U.S. dollars, pre-tax in 2018 dollars
Assume 7% interest rate and 20-year life for annualized cost.

2.2 EPA appears to have underestimated the peak FGD wastewater design flow used to size equipment by assuming many facilities can reduce flow to average flows to reduce wastewater treatment costs. But, many facilities will have FGD operational limits, in addition to chlorides, that will prohibit reducing flow rate.

In the 2013 proposed ELG rule, EPA stated that they estimated flows for some FGD wastewater treatment systems based on the typical or average flow reported by the power plant, then multiplied that average flow rate by a "mean capacity factor" of 1.99. This is a standard industry approach, as treatment systems must be able to treat to compliance levels at all operating

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conditions. However, in the 2019 cost estimate calculations, it appears that EPA does not multiply by a mean capacity factor [ERG, 2019b], instead asserting that plants can reduce flow so designing for current average flow can provide adequate conservatism.

In practice, wet FGD systems typically manage their recycle based on their chloride/halogen concentrations, to protect the materials of construction, as well as their concentration of fines or other operational considerations; thus flows can vary. Higher concentrations of fines could potentially disrupt gypsum dewatering, gypsum quality, and oxidation-reduction potential (ORP) stability in some wet FGD systems; flow could thus increase over reported averages. In addition, longer residence times in the FGD absorbers due to reduction in FGD purges would lead to concentrating trace metal levels, which could potentially increase mercury flue gas re-emissions in some wet FGD systems. EPA's approach of assuming that facilities can reduce flow rates is a very broad and inaccurate assumption which leads to underestimating the size and cost of treatment systems.

EPRI reviewed the flows reported by EPA and used best professional judgement to resolve flow changes from the 2009 ICR response. Then EPRI estimated a peak flow for each plant in one of four ways:

- If EPA's 2019 FGD purge flow matched the plant's reported typical purge flow (ICR response B5-2) or if it appeared that EPA made reasonable adjustments to the plant's reported typical purge flow based on units added/retired since the ICR response, then EPRI used EPA's assumed FGD purge flow. To determine peak flow, EPRI multiplied EPA's FGD purge flow by a peaking factor of 1.5.
- For two plants, there was insufficient information to understand why EPA had reduced the plant's reported purge flow since the ICR response. For these plants EPRI used the plant's original ICR response for FGD purge flow (ICR response B5-2) and then applied a peaking factor of 1.5 to determine the plant's peak flow.
- EPRI used the plant's reported peak wastewater treatment system (WWTS) design flow (ICR response D5-3), where it was more suitable in EPRI's best professional judgment. No peaking factor was applied where EPRI used the plant's reported peak WWTS design flow.
- For two plants, EPRI used a peak flow basis derived from the original FGD WWTS design flow (ICR response D5-3), which was adjusted based on units added/retired since the ICR response.

For the total industry-wide flow of FGD wastewater needing treatment, EPRI used 53 million gallons per day (MGD) while EPA used 35 MGD. This difference in flow rates is a major element in the cost differences between EPA and EPRI.

2.3 EPA appears to have underestimated the cost factors it used to create a cost estimate for each individual plant. Cost factors more typical of an industry standard engineering estimate are more appropriate.

EPA should clarify their detailed, bottoms-up estimating methodology for costs other than those for major equipment from vendors. While insights are available in Table 1 of the ERG 2019 memorandum *Updated Flue Gas Desulfurization Low Residence Time Reduction (LRTR) Cost Methodology* [ERG, 2019d], the scope of what ERG refers to as the "Missing Capital Cost" is not presented in the ERG memo. The ratio of the total LRTR capital cost to the vendor

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equipment cost used by EPA is roughly 1.6, as shown in Table 2-3. When EPRI evaluated what is included in the vendor's cost, and applied standard engineering practice cost estimating [AACE, 2011b] to compute total installed cost, the ratio was roughly 2.5 times, as shown in Table 2-4. A detailed breakdown of what EPRI included is presented in Appendix B of these comments.

Table 2-3
EPA's estimated LRTR total capital costs for low-nitrate and high-nitrate systems [ERG, 2019d]

FGD Flow (GPD)	Updated Vendor Capital Cost (2018$)	Missing Capital Cost (2018$)	Building Capital Cost (2018$)	Transportation & Disposal Capital Cost (2018$)	Updated Total LRTR Capital Cost (2018$)	*Calculated Ratio of Total LRTR Capital Cost to Vendor Capital Cost*
Low Nitrates						
144,000	$2,840,000	$1,560,000	$270,000	$23,400	$4,700,000	*1.7*
432,000	$4,020,000	$2,210,000	$300,000	$32,700	$6,560,000	*1.6*
864,000	$5,690,000	$3,130,000	$300,000	$45,600	$9,160,000	*1.6*
1,728,000	$8,140,000	$4,480,000	$330,000	$64,700	$13,000,000	*1.6*
High Nitrates						
144,000	$3,430,000	$1,890,000	$270,000	$28,000	$5,620,000	*1.6*
432,000	$4,810,000	$2,640,000	$300,000	$38,700	$7,790,000	*1.6*
864,000	$6,770,000	$3,720,000	$300,000	$53,900	$10,800,000	*1.6*
1,728,000	$9,710,000	$5,340,000	$330,000	$76,900	$15,500,000	*1.6*

GPD = gallons per day
LRTR = low residence time reduction

Table 2-4
EPRI's estimated LRTR total capital costs for a 300-gpm high-nitrate system (from Table B-5 and Table B-6 of Appendix B)

FGD Flow (GPD)	Updated Vendor Capital Cost (2018$)	Updated Total LRTR Capital Cost (2018$)*	*Calculated Ratio of Total LRTR Capital Cost to Vendor Capital Cost*
432,000	$5,280,000	$13,060,000	*2.5*

GPD = gallons per day
LRTR = low residence time reduction
* = Detailed breakdown of what EPRI included to calculate total cost is presented in Appendix B of these comments

The factors provided in Table 2-5 reflect industry standard practice and should be used to calculate the total estimated cost of a biological treatment system. EPRI applied these factors to the total purchased equipment cost to calculate a total estimated cost for a biological treatment system. The values used are based on industry experience [CH2M, 2009; AACE, 2011b] and standard engineering practice for all industrial sectors. These factors were used by EPRI to

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calculate a total estimated cost for each of the plants included in the calculation of industry cost. By excluding or underestimating these items, it appears that EPA has underestimated the cost of treatment systems for each facility and accordingly, overall industry costs.

EPA may have underestimated the additional costs for site work contractor profit, etc., needed to estimate total installed cost of biological treatment. Table 2-5 provides a summary of cost factors that EPRI applied to each facility to develop its cost estimate for biological selenium treatment. EPRI applied different cost factors to the "non-SeHAWK system costs" which include an inline selenium monitor and chemical addition for ORP control. An inline monitor for selenium will be required to optimize process control and to reduce the likelihood of permit violations because turnaround times from offsite laboratories (utility and commercial) will be too long (i.e., several days) to be used for treatment process control. However, the technical feasibility of inline selenium monitors has not been demonstrated, and their cost impacts are uncertain.

Table 2-5
Biological treatment cost factors in EPRI estimate for Frontier SeHAWK® system

Additional Cost Items	Value Used (%)	Rationale for Selected Value
Cost Factors Applied to SeHAWK® System Cost		
Site work	3	Assumes SeHAWK® system will be co-located with physical/chemical treatment plant. Site will be made "pad ready" as required by Frontier.
Concrete	–	Concrete for the SeHAWK® system is included in Frontier cost.
Piping	5	Lower than range. Frontier's costing includes piping skids, and piping interior to bioreactors, but not costing for field-installed piping, which would run to and from the SeHAWK® system and also between stage 1 and stage 2 bioreactors.
Miscellaneous metals, finishes	–	Frontier cost curve provides miscellaneous metals costs for items within the SeHAWK® system. Items outside the SeHAWK® system are covered by tie-in allowance.
Mechanical, heating/ventilation/air conditioning	–	Not included
Electrical	5	Lower than industry's typical range. Frontier's electrical estimates include rotating equipment and instrumentation required for process equipment, with electrical consumption weighted by duty type (continuous vs. intermittent). Capital electrical costs not in Frontier's scope include items such as motor control centers and disconnects for motors, plant air supply, as well as installation of field wiring.
Instrumentation and control	–	I&C for SeHAWK® system is included in Frontier cost.
Tie-in/Integration	10	Includes items such as integrating SeHAWK® controls into plant DCS and SCADA; pipe interconnections; and extending power, control wires, and piping to the SeHAWK® system.
General contractor general conditions	5	Used lower number than typical because majority of equipment is SeHAWK® system.

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Table 2-4 (continued)
Biological treatment cost factors in EPRI estimate

Additional Cost Items	Value Used (%)	Rationale for Selected Value
Cost Factors Applied to SeHAWK® System Cost		
General contractor profit	12	Used lower number, as majority of equipment is SeHAWK® system.
Miscellaneous unidentified cost	20	Contingency of 20 percent is consistent with a Class 4 estimate.
Engineering (design, services during construction, startup, and operator training)	–	Engineering for the SeHAWK® system is included in Frontier cost.
Client administrative and overhead	7	Higher than range, assumes it also includes early engineering and geotechnical investigation.
Cost Factors Applied to All Non-SeHAWK® System Costs [1]		
Site work	4	Mid-point of range.
Concrete	–	Concrete for non- SeHAWK® system costs is included in the equipment cost.
Piping	25	Higher than range, assumes installation of high-grade alloy.
Miscellaneous metals, finishes	15	High-point of range.
Mechanical, heating/ventilation/air conditioning (HVAC)	7.5	Mid-point of range.
Electrical (process electrical and site electrical)	22	Mid-point of range.
Instrumentation and control	15	Mid-point of range.
Tie-in/Integration	5	This includes items such as integrating system controls into the plant DCS and SCADA; pipe interconnections; and extending power, control wires, and piping to system.
General contractor general conditions	12.5	Mid-point of range.
Bonding and insurance	2.85	Mid-point of range.
General contractor profit	14.25	Mid-point of range.
Miscellaneous unidentified cost	20	Mid-point of range.

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Table 2-4 (continued)
Biological treatment cost factors in EPRI estimate

Additional Cost Items	Value Used (%)	Rationale for Selected Value
Cost Factors Applied to All Non-SeHAWK® System Costs [1]		
Engineering (design, services during construction, startup, and operator training)	20	Mid-point of range.
Client administrative and overhead	7	Higher than range, assumes it also includes early engineering and geotechnical investigation.

DCS = distributed control system
HVAC = heating, ventilation, and air conditioning
I&C = instrumentation and control
SCADA = supervisory control and data acquisition
Frontier SeHAWK® is described in [ERG 2019d, Appendix B]
[1] Non-SeHAWK® System Costs include selenium monitor (all plants) and chemical addition system for oxidation reduction potential (ORP) control (some plants).

EPRI has reviewed the non-confidential business information (non-CBI) supplied in the public docket [EPA, 2019a]. EPRI generally agrees with the purchased equipment costs for treatment systems treating a range of wastewater flow rates. EPRI has taken a similar approach by obtaining vendor quotations for various flow rates for each major piece of equipment in order to develop cost curves. Using these cost curves, EPRI has generated a cost model for chemical precipitation treatment and biological treatment equipment similar to the model EPA created and described in *Incremental Costs and Pollutant Removals for the Proposed Effluent Limitations Guidelines and Standards for the Steam Electric Generating Point Source Category* [EPA, 2013]. The methodology EPRI used to create this cost model is described further in Appendix A (Chemical Precipitation) and Appendix B (Biological) of these comments.

According to the Association for the Advancement of Cost Engineering International (AACE) guidance, cost models based on definitive cost estimates and standard design information can be used for various facility or plant costs at the planning stage, and are often used for conceptual cost estimating [AACE International, 2011a], for Class 5 or Class 4 estimates. (See Table A-3 in Appendix A for additional information). Costs developed from these curves are then generally factored to determine the overall capital cost of a project early in the conceptual planning phase [AACE International, 2011b].

2.4 EPA underestimated required FGD chemical precipitation equipment redundancy.

The cost of chemical precipitation treatment is significantly affected by the approach used to define redundancy in treatment trains. The redundancy required differs from the redundancy of specific mechanical equipment (such as providing a spare pump); but rather refers to defining redundant treatment trains in terms of major equipment such as clarifiers. Most treatment systems for critical functions include redundant trains in case of failure or for use during maintenance.

There is then a question of the size of each train. A conservative approach is to provide capacity to treat the entire peak design flow with one train out of service, which can be done with 2x100%

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or 3x50% sizing. Providing smaller trains (such as 2x60%) is used in some situations where the risks associated with not being able to treat all the water all the time are considered acceptable. In 2013, EPA assumed treatment trains of 2x60% [EPA, 2015]. EPRI commented that a more appropriate sizing is 2x100%. In 2015, EPA rejected this comment. Based on how newer treatment systems are being designed and operated, EPRI understands that the industry's approach to response to redundancy will generally vary, based on different utility operational strategies as well as base load versus peaking units. EPRI believes that redundancy is best represented by a range of system redundancies and has assumed, with member feedback, that plants with a reported capacity factor greater than 60 percent (26 percent of the coal generation industry) would install a 2x100% redundancy system. Similarly, EPRI assumes that the remaining plants with reported lower capacity factors (74 percent of industry plants) would install a 2x60% redundancy system.

2.5 EPA appears to have underestimated cost at plants with high-TDS FGD water.

Higher-salinity water, and swings in FGD water salinity which can occur due to FGD system operational variability and variability can cause operational challenges in biological treatment. Frontier states they have demonstrated, "... successful treatment of a broad range of FGD water chemistries, with TDS averaging 17,556 mg/L (36,000 mg/L maximum) and chloride averaging 7,000 mg/L (17,200 mg/L maximum)" [ERG, 2019d]. However, in a recent EPRI pilot test with FGD wastewater of approximately 35,000 milligrams per liter (mg/L) total dissolved solids (TDS) by another leading biological treatment vendor (Suez), the vendor needed to dilute influent to below 20,000 mg/L TDS [EPRI, 2018]. Such blending to lower TDS increases the cost of treatment as it increases flow rate and would likely reduce the ELG limits due to the combined waste formula. EPRI assumed three percent of plants would require mixing with lower-salinity water, which increased industry cost by 0.2 percent.

2.6 EPA's bioreactor costs appear to be underestimated because they were provided by the vendor based on achieving higher selenium limits.

Frontier provided the EPA with a cost estimate for its supplied equipment in an LRTR system that, "... is designed to meet the specified water quality parameters of 50 micrograms per liter (µg/L) selenium, 356/788 nanograms per liter (ng/L) mercury, 8/11 ng/L arsenic, and 4.4/17 mg/L Nitrate-N ..." [ERG, 2019d]. The proposed 2019 ELG limits are set with a lower monthly average limit for selenium (as well as mercury and nitrate-N) [EPA, 2019b]. This may require the bioreactor supplier to provide more residence time to reach the lower monthly average ELG for selenium by providing a larger bioreactor (at higher cost). EPA should document what impact, if any, the actual proposed BAT limits would have on the cost of an LRTR system.

2.7 EPA used a revised cost estimate from the bioreactor equipment vendor that is not representative of bioreactors in use.

Frontier provided EPA with a cost estimate for its supplied equipment in an LRTR system in September 2019 [ERG, 2019c]. This replaced their estimated costs provided to EPA in May 2018. The September 2019 cost estimate was significantly lower than the 2018 estimate. The price reductions differed with flow rate, ranging from nearly 30 percent at low flows (100 to 300 gpm) to nearly 50 percent at high flows (1,200 gpm). It is noted that this updated pricing is very new.

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2.8 References

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ERG, 2019d. Eastern Research Group, Inc. Eastern Research Group, Inc. *Updated Flue Gas Desulfurization Low Residence Time Reduction (LRTR) Cost Methodology.* EPA-HQ-OW-2009-0819-8156. October 8.

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EXHIBIT 8

Talking Points for Steam Electric Option Selection Opening Remarks
6/29/21

- The purpose of this briefing is to present options for responding to litigation on the 2020 Steam Electric Reconsideration Rule (2020 rule).
- Other drivers include EO 13990 and the administration's power sector priorities.
- OW is responsible for developing legally defensible Effluent Limitations Guidelines rules (ELGs) for a range of industries and did so for coal-fired power in 2015, revising it again in the 2020 rule.
- ELGs are designed to target water pollution, however, OW has been excited to have robust discussions with OLEM, OAR, OP, and OGC about how the ELG might contribute Ex. 5 Deliberative Process (DP)
- Finalizing an ELG is a data intensive effort and therefore a resource intensive process. At this time, we can support 2-3 concurrent ELG rulemakings with current staffing and budget, depending on the scope and timing of the rulemakings.
- Ex. 5 Deliberative Process (DP)

Ex. 5 Deliberative Process (DP)

BRIEFING MEMO
June 29, 2021

MEMORANDUM FOR THE ADMINISTRATOR

FROM: Radhika Fox, OW, 202-XXX-XXXX, Fox.Radhika@epa.gov

SUBJECT: Steam Electric Reconsideration Option Selection

DATE: Tuesday June 29, 2021

TIME: 9:30 – 10:30 AM EST

I. REQUESTING OFFICE

Office of Water, Office of Science and Technology

II. TIMING

This briefing is driven by: Executive Order 13990 directing EPA to reconsider the rule, ongoing litigation currently held in abeyance until July 26, 2021, and the Agency's cross-office power sector strategy.

III. PURPOSE

To receive feedback on options for implementing or revising the 2020 Steam Electric Effluent Limit Guideline (2020 rule). Ex. 5 Deliberative Process (DP)

Ex. 5 Deliberative Process (DP)

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IV. BACKGROUND AND HISTORY (BULLETS ARE FINE)

- In 2015 EPA finalized revision to the Steam Electric Effluent Guidelines, the first update to this rule since 1982.
    - On September 18, 2017 EPA announced it was delaying implementation of the 2015 rule and initiating a new rulemaking.
- In 2020 EPA finalized revisions to the 2015 rule.
- Differences between the 2015 rule and the 2020 rule include:
    - Changes to limits and compliance dates for Flue Gas Desulfurization (FGD) wastewater
        - Relaxed numeric limits for selenium
        - Tightened limits for nitrogen and mercury
        - Compliance date extended from 2023 to 2025
    - Changes to limits and compliance dates for FGD wastewater voluntary incentives program
        - Relaxed limits for mercury and TDS
        - Tightened limits for selenium
        - Created new limits for bromide and nitrogen
        - Compliance date extended from 2023 to 2028
    - Changes to limits and compliance dates for bottom ash transport water
        - Relaxed zero discharge limit to a case-by-case volumetric purge not to exceed 10 percent of system volume
        - Compliance date extended from 2023 to 2025
    - Created new subcategories
        - High-FGD flow plants
        - Low-utilization electric generating units (peakers)
        - Electric generating units ceasing coal combustion by 2028
- After promulgation of the 2020 rule EPA is evaluating whether revision to the existing regulation is necessary for three reasons:
    - Executive Order 13990 (the 2020 Steam Electric ELGs are is listed as a rule for EPA to consider revising)

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- Litigation on 2020 Rule has been consolidated in *Appalachian Voices et al. v. EPA*, No. 20-2187 (4th Cir.)
  - Petitions for review of the 2020 rule were filed by multiple environmental groups
  - Electric utilities and trade associations have intervened to defend the 2020 rule
  - The litigation is currently being held in abeyance until July 26
  - EPA is expected to make a decision to revise or not revise the 2020 Steam Electric ELGs ELG by this time
- Cross-office power sector strategy

Ex. 5 Deliberative Process (DP)

V. KEY ISSUES

Ex. 5 Deliberative Process (DP)

VI. REGULATORY SUMMARY (IF APPROPRIATE)

Ex. 5 Deliberative Process (DP)

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Ex. 5 Deliberative Process (DP)

VII. ADDITIONAL POLICY OR TECHNICAL INFORMATION (IF APPROPRIATE)

The attached power point provides additional information.

VIII. ANTICIPATED STAKEHOLDER REACTION

Ex. 5 Deliberative Process (DP)

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IX. STAKEHOLDER INVOLVEMENT

OW has had preliminary engagement with a wide range of stakeholders including: environmental petitioners, academic researchers, biological treatment and membrane filtration vendors, electric utilities, and trade associations.

X. ROLL-OUT AND COMMUNICATIONS PLAN

Upon selection of an option EPA and DOJ would respond to the courts regarding the ongoing litigation, and EPA would also have a formal rollout that would include involvement from the Office of the Administrator and from OW. The substance of the legal response and rollout activities would be dependent on the option selected

XI. NEXT STEPS/UPCOMING DEADLINES

We are seeking feedback on how to proceed with the implementation and potential revisions of the 2020 Rule. EPA and DOJ must respond to the courts by July 26, 2020 on EPA's intent to revise the 2020 rule.

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EXHIBIT 9

The New York Times https://www.nytimes.com/2022/07/07/climate/epa-greenhouse-gas-power-plant-regulations.html

E.P.A. Describes How It Will Regulate Power Plants After Supreme Court Setback

Last week's ruling took away a major tool for reducing greenhouse gas emissions. Many regulatory options still remain, but the path will be more difficult.



By Lisa Friedman

July 7, 2022

WASHINGTON — Following the Supreme Court's landmark ruling last week limiting the government's ability to restrict the pollution that is causing global warming, the Biden administration is planning to use other regulatory tools in hopes of achieving similar goals.

A key part of the plan: Further restrict other pollutants that coal-burning power plants emit such as soot, mercury and nitrous oxides — a move that also will reduce greenhouse gas emissions.

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"While the Court sided with special interests trying to take the country backwards, it did not take away E.P.A.'s ability to regulate greenhouse gases and protect people from pollution," Gina McCarthy, the White House climate change adviser, said in a statement, referring to the federal Environmental Protection Agency.

White House officials said they believe President Biden's goal of slashing emissions roughly in half by the end of this decade, and fully eliminating fossil fuel emissions from the power sector by 2035, still remains well within reach. The falling cost of renewable energy like wind and solar will help, administration officials said, as well as an increasing number of policies at the state and local levels to fight climate change, along with the new E.P.A. regulations.

Sign up for the Climate Forward newsletter Your must-read guide to the climate crisis. Get it in your inbox.

Still, the federal government's piecemeal approach, which is still taking shape, could make it tougher to achieve its goals, many observers said. Power plants that burn fossil fuels are one of the single largest contributors of carbon dioxide to the atmosphere, which is rapidly warming the planet.

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The Supreme Court's 6-3 decision, which concluded that the E.P.A. lacks broad authority to transform the nation's electrical system away from fossil fuels, has left the Biden administration bereft of a powerful tool, energy experts said. The ruling did not strip the E.P.A. of its authority to regulate greenhouse gas emissions, but it allowed only narrower policies to regulate how individual power plants operate.

That means the administration's backup strategies are not likely to spur a rapid metamorphosis to clean energy unless the administration acts quickly and aggressively, experts said. "This year and early next are critically important for whether or not the goals the administration has set — both for the power sector and the economy as a whole — are going to be reachable," said John Larsen, a partner at the Rhodium Group, an energy research and consulting firm.

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Gina McCarthy, the White House climate change adviser, said in a statement that the court "did not take away E.P.A.'s ability to regulate greenhouse gases." Al Drago for The New York Times

Mr. Larsen said the Biden administration will have to enact "layers and layers" of new policies rather than rely on a single sweeping program. And, he added, "they need to act soon to actually get those wheels turning."

In an interview this week, Joseph Goffman, President Biden's nominee for E.P.A.'s air chief, said the agency intends to issue a proposed regulation early next year that will curb greenhouse gas emissions from existing coal-burning power plants. The E.P.A. around the same time also will issue a proposed regulation to cut emissions from new gas-burning power plants, he said.

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Mr. Goffman declined to discuss details of what either plan might include, but said the E.P.A. has been "putting together a menu of three or four different approaches" that would fit within the Supreme Court's mandate.

Mr. Goffman said the E.P.A. is still analyzing the Supreme Court ruling but said it doesn't appear to affect the agency's current strategy. "The case did not really take anything off the menu that we've been focusing on," he said.

He said the administration's climate goals can be reached, but it will take more actions across the government, not just through the E.P.A. "We were never going to get there other than through an ensemble of policies," Mr. Goffman said.

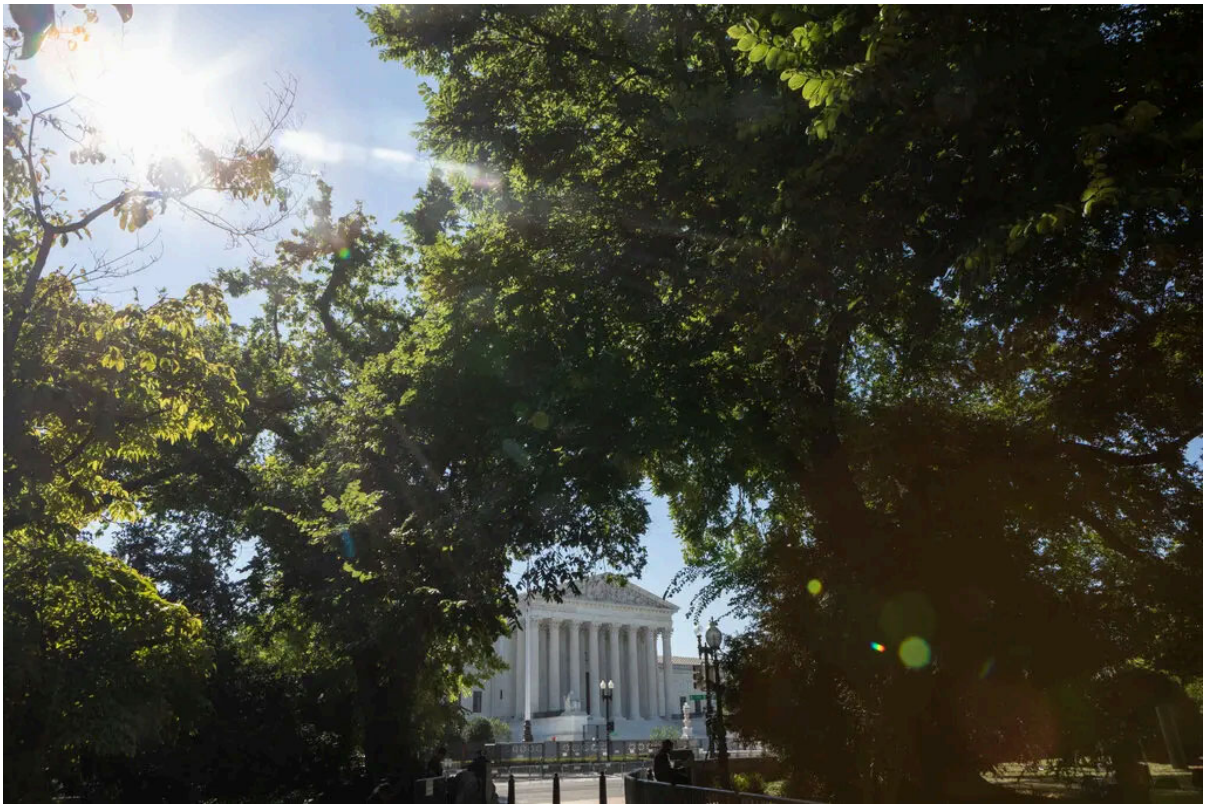
The E.P.A. also is enacting tougher restrictions on coal plants to reduce pollutants like soot and nitrous oxides, and to force the cleanup of water contamination from coal plants. Michael S. Regan, the E.P.A. administrator, has said those and other rules will have a side-benefit of also reducing greenhouse gas emissions. He also has indicated rule changes such as these might make some coal plants too expensive to continue to operate, resulting in more of them being closed down.

"By presenting all of those rules at the same time to the industry, the industry gets a chance to take a look at this suite of rules all at once and say, 'Is it worth doubling down in investments in this

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current facility? Or should we look at that cost and say now it's time to pivot and invest in a clean energy future?'" Mr. Regan said at an oil and gas conference in March.

"If some of these facilities decide that it's not worth investing in, and you get an expedited retirement, that's the best tool for reducing greenhouse gas emissions," he said.



The Supreme Court's ruling didn't strip the E.P.A. of its authority to regulate greenhouse gas emissions, but narrowed some regulatory options. Anna Rose Layden for The New York Times

Coal provides about 21 percent of electricity in the United States, but accounts for more than half of all carbon dioxide emissions from power production, making it one of the dirtiest fossil fuels. About 28 percent of coal-fired capacity is expected to be retired by

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2035, according to the Energy Information Administration, a change that has been driven largely by the fact that gas-burning power plants have become less expensive to operate, as has renewable energy.

One person familiar with the Biden administration's approach said the White House believes it can achieve economywide emissions reductions of as much as 40 percent below 2005 levels by the end of this decade by tightening regulations on traditional pollutants like mercury, acid gases and particulate matter. That would get the country close to Mr. Biden's goal of cutting emissions at least 50 percent from 2005 levels in that same time frame, said the person, who was not authorized to speak publicly about the administration's strategy.

Environmental activists said they are uncertain about the Biden administration's commitment.

"What we're seeing right now is the Biden administration not acting with the urgency necessary," said Weston Gobar, a spokesman for the Movement for Black Lives, a coalition of Black-led social justice and environmental groups. He called on Mr. Biden to declare a "climate emergency" under the National Emergencies Act in order to quickly build out clean energy resources, and to urge Congress to suspend the filibuster to pass climate bills.

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He praised the emerging E.P.A. strategy, noting the bulk of pollution from power plants disproportionately affects communities of color. But, he said, “It’s not enough.”

Meanwhile, when it comes to directly regulating greenhouse gas emissions from power plants, several experts said the E.P.A. could call for blending relatively cleaner fuels, like gas or hydrogen, to bring down emissions, along with other technological fixes, such as trapping carbon dioxide from power plants before the emissions can enter the atmosphere.

Michelle Bloodworth, chief executive of America’s Power, a coal industry group, said that an aggressive agenda that drives more coal plant retirements would hurt the reliability of the electric grid.

“Electric grid officials have issued warnings about the prospect of electricity shortages and blackouts in many parts of the country, and more coal retirements would only make the situation worse,” Ms. Bloodworth said in a statement. She noted that more than 40 percent of the nation’s coal fleet has already announced plans to shut down.

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The Capitol Power Plant, a fossil-fuel-burning facility that serves the United States Capitol. Nationwide, 28 percent of coal-burning capacity is expected to be retired by 2035. T.J. Kirkpatrick for The New York Times

Yet eliminating emissions from those plants, or pushing the power plants to move to cleaner fuels, also is critical to keeping global rising temperatures at relatively safe levels. Also key: how the E.P.A. proposes regulating emissions from more than 90 gigawatts of new gas-burning plants that are being planned, said Leah Stokes, a professor of environmental policy at the University of Santa Barbara, California.

“That’s going to be hugely consequential for the planet,” Ms. Stokes said. “If we don’t have a plan for new gas plants, we will not meet President Biden’s goals.”

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Jeffrey Holmstead, an energy lawyer who served in the E.P.A. in both Bush administrations, said the utility companies he works with feel that new regulations on their power plants are a "sideshow" compared with the emissions cuts that could be achieved if Congress approved billions of dollars in tax credits for wind, solar and battery storage. That package is still being negotiated in Congress because of objections from Senator Joe Manchin III, Democrat of West Virginia, whose vote is key in the evenly divided Senate.

"It will be interesting to see how aggressively the administration moves to regulate CO2 emissions," Mr. Holmstead said. "What's unclear is how high a priority that will be for the agency."

Scientists say that if warming exceeds 1.5 degrees Celsius above preindustrial levels, the likelihood of catastrophic consequences from climate change — worsening heat waves and droughts, intensifying storms, and other crises — increases significantly. The planet has already heated by an average of about 1.1 degrees Celsius, and worldwide emissions continue to climb.

Lisa Friedman reports on federal climate and environmental policy from Washington. She has broken multiple stories about the Trump administration's efforts to repeal climate change regulations and limit the use of science in policymaking. More about Lisa Friedman

A version of this article appears in print on , Section B, Page 1 of the New York edition with the headline: E.P.A. Has Backup Plan For Emissions After Setback

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EXHIBIT 10

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October 14, 2021

Dr. Phillip Flanders
Engineering and Analysis Division
Office of Water
4303T
U.S. Environmental Protection Agency
1200 Pennsylvania Ave. NW
Washington, DC 20460

Re: **EPA's Notice of Availability of the Preliminary Effluent Guidelines Program Plan 15, EPA–HQ–OW–2021–0547; FRL–5601.5–01–OW, 86 Fed. Reg. 51,155 (Sept. 14, 2021)**

Dear Dr. Flanders:

Attached are the Comments of the Utility Water Act Group (UWAG) in response to EPA's Notice of Availability of the Preliminary Effluent Guidelines Program Plan 15, 86 Fed. Reg. 51,155 (Sept. 14, 2021). UWAG appreciates the opportunity to comment. Please contact me at (202) 955-1629 if you have any questions.

Sincerely,

Brian Levey

Brian R. Levey

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Comments of the Utility Water Act Group in Response to the U.S. Environmental Protection Agency's Preliminary Effluent Guidelines Program Plan 15

EPA–HQ–OW–2021–0547; FRL–5601.5–01–OW

October 14, 2021

www.utilitywateractgroup.org

On September 14, 2021, the U.S. Environmental Protection Agency (EPA) announced the availability of the Preliminary Effluent Guidelines Program Plan 15 (PP15) and requested public input on a number of issues. 86 Fed. Reg. 51,155 (Sept. 14, 2021). In particular, EPA solicited comments on its rulemaking activities, including the Agency's July 26, 2021 announcement to revise effluent limitations guidelines (ELGs) for the Steam Electric Generating point source category. In addition, EPA solicited comments on the capabilities, performance, and costs of membrane treatment technologies. The Utility Water Act Group (UWAG)[1] submits these comments to respond to EPA's request for comment on these two topics.

UWAG members must make substantial investments of time and money to comply with technology-driven requirements of the ELGs promulgated in 2020 with a major deadline occurring just yesterday, while at the same time EPA is undertaking a new rulemaking to potentially change those very requirements. These current requirements imposed by the 2020 Steam Electric ELG Reconsideration Rule, 85 Fed. Reg. 64,650 (Oct. 13, 2020) ("2020 Rule") affect not only electric utility companies, but also impact state regulators as well as consumers. Accordingly, UWAG requests that EPA consider ways to avoid the potential waste of those investments of time and money as it considers its approach to a new proposed rule.

EPA acknowledged in the 2020 Rule that the record does not support establishing discharge limits based on membrane technology due, in part, to the costs, non-water quality environmental impacts, and lack of commercial-scale demonstration for managing the concentrated brine and solid waste generated by the membrane treatment process. *See* 85 Fed. Reg. at 64,666-68. UWAG agrees with EPA's assessment in the 2020 rulemaking and has significant concerns about the availability and economic achievability of membrane technology in the steam electric context, including but not limited to the availability of proven, cost-effective methods for disposing the concentrated waste streams produced by membrane systems. Very little research has been completed since the 2020 rulemaking on the efficacy of membrane filtration technology, particularly on brine management. Thus, significant data gaps and uncertainty remain.

I. UWAG members are leading the development of newer and cleaner electric energy sources, and making substantial investments to comply with the 2020 ELG Rule.

UWAG supports the 2020 Rule, and its members are investing significant time and resources into analyzing and pursuing compliance options to meet the deadlines of the 2020 Rule. To comply with the 2020 Rule, UWAG members are employing new technologies to further treat waste streams, and are planning to substantially reduce or cease coal combustion at a number of units, all while striving to ensure a reliable and affordable supply of electricity. These

[1] UWAG is a voluntary, non-profit, unincorporated group of member companies (including individual electric power generation or transmission and distribution companies and cooperatives, and their affiliates) and representative national industry trade associations. The individual energy companies operate power plants and other facilities that generate, transmit, and distribute electricity to residential, commercial, industrial, and institutional customers. UWAG's purpose is to participate on behalf of its members in EPA's rulemakings under the Clean Water Act and in related proceedings.

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efforts play a central role in the industry's transition to newer and cleaner energy sources. The costs of implementing these changes in technology and generation typically are reflected in the rates paid by residential, commercial, and other customers. In regulated markets, those changes and costs are closely scrutinized by public service commissions and other bodies that regulate capital investments as well as the recovery of those costs through electricity rates. Independent power producers often bear the direct initial costs of these investments, then seek to recover these costs from the sale of the electricity. In the case of not-for-profit public power utilities and electric cooperatives, which have no stockholders, these costs are directly borne by consumers. In many cases, these consumers include rural, minority, and low-income communities (for example, 92% of the nation's persistent poverty counties are served by electric cooperatives).

It takes years for a facility to raise capital, plan, design, and procure equipment, construct, and test systems necessary to comply with the ELGs.[2] If a facility proceeds through procurement and installs the best available technology economically achievable (BAT) to comply with the 2020 ELGs and upcoming deadlines, and then EPA revises the ELGs in a future rule to specify different requirements based on use of a different technology (*e.g.*, membranes), the facility will be forced to expend additional resources to comply with the new requirements.[3] To keep the facility running and thereby provide reliable baseload power, companies will seek electricity rate increases or seek to sell the electricity they generate at a higher price to cover the additional capital expenditures and operation and maintenance costs.

According to EPA's recent announcements and PP15, the requirements and deadlines established by the 2020 Rule remain current and "will be implemented and enforced." PP15 at 7-1. For facilities preparing to comply with the new 2020 generally applicable ELG requirements, substantial investments of time and resources are already well underway – with compliance requirements starting as soon as yesterday (October 13, 2021). For flue gas desulfurization wastewater (FGDW) and bottom ash transport water (BATW), the 2020 Rule mandates that facilities must comply with the new applicable effluent limitations "by a date determined by the permitting authority that is as soon as possible beginning October 13, 2021,

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[2] *See*, *e.g.*, 80 Fed. Reg. 67,838, 67,854 col. 2 (Nov. 3, 2015) and 85 Fed. Reg. at 64,683, col. 2 ("… EPA's rulemaking record indicates a typical time frame of 26 to 34 months to raise capital, plan and design systems (including any necessary pilot testing), procure equipment, and construct and then test systems (including a commissioning period for FGD wastewater treatment systems). For BA transport water, the record at proposal indicated a typical time frame of 15 to 23 months to raise capital, plan and design systems, procure equipment, and construct a dry handling or closed loop or high recycle rate BA system.").

[3] Many of these same points were made in UWAG's September 3, 2021 reply brief in the ongoing ELG litigation, in which UWAG (as did EPA in its reply brief) opposed the Petitioners' request to limit an abeyance of those proceedings to six months. *See* UWAG Reply Br. at 4, *Appalachian Voices et al. v. EPA*, No. 20-2187, ECF No. 72 (4th Cir. Sept. 3, 2021) ("EPA's announced plan to conduct further rulemaking while the electric utility industry is in the midst of committing millions of dollars and extensive human resources to implement the current rule could produce an untenable waste of limited resources, but EPA could address that problem by undertaking an expedited rulemaking to suspend or delay the existing deadlines or to create other avenues for interim deadline relief.").

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but no later than December 31, 2025." 40 C.F.R. §§ 423.13(g)(1)(i), (k)(1)(i). As noted above, to meet these deadlines, UWAG members already have invested significant time and resources to analyze and pursue new treatment technologies (and in some cases have already constructed and installed treatment technologies) to comply with the applicable limits.

For facilities that intend to pursue any of the rule subcategories based on permanent cessation of coal combustion,[4] low utilization of the electric generating unit, or participation in the FGDW voluntary incentives program (under limits more stringent than the new 2020 generally applicable ELG requirements), owners and operators were required to file a Notice of Planned Participation (NOPP) by October 13, 2021. *See* 40 C.F.R. §§ 423.19(e), (f), and (h). Based on the underlying planning, cost and regulatory commitments required for such NOPPs, EPA should not propose any changes that would reduce or otherwise adversely impact the timeframes for meeting those commitments (since such changes could result in additional costs and burdens on owners and operators, regulators and the public that would be disproportionate to any potential benefit).

If EPA's new rulemaking seeks to establish new limits based on the installation and operation of different technologies at substantial additional costs,[5] EPA should consider ways to avoid the potential for significant waste of investment in and construction of treatment systems that may soon be superseded.[6] For example, EPA could consider measures to ensure that entities who have made investments of money and time to comply with the 2020 ELG Rule may continue to rely on those investments for future ELG compliance.

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[4] In the 2020 Rule, EPA ruled out imposing new technology-based requirements on units that will cease coal combustion by 2028 "due to the unacceptable disproportionate costs they would impose; the potential of such costs to accelerate retirements of EGUs at this age of their useful life; the resulting increase in the risk of electricity reliability problems due to those accelerated retirements; and the harmonization with the CCR rule." 85 Fed. Reg. at 64,682. UWAG supports the limits in this subcategory, which allow companies to continue the organized retirement or repowering of EGUs that are no longer economical.

[5] Lost expenditures on compliance with the 2020 Rule under the current deadlines and shorter amortization periods would likely need to be accounted for in any determination by EPA of whether imposing new requirements based on implementation of different technology would be "economically achievable" for the steam electric industry within the meaning of the statute. To the extent that facilities retire units sooner than anticipated due to new regulatory or economic requirements, EPA may need to account for this potential smaller amortization timeline when it assesses whether other technologies are economically achievable in a new rulemaking.

[6] Such a potential waste of resources is also disproportionate to and unsupported by the priority identified for the steam electric category in PP15 (which in Table 5-1 ranks steam electric lower than 24 other point source categories *even before* application of the new requirements in the 2020 Rule).

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II. UWAG agrees with EPA's conclusion in the 2020 rulemaking that membrane treatment systems are not the best available technology economically achievable.

PP15 states that "treatment systems using membranes have advanced since the 2020 rule's issuance and continue to rapidly advance as an effective option for treating a wide variety of industrial pollution, including from steam electric power plants. EPA expects this technology to continue advancing and the agency will evaluate its availability … as part of the new rulemaking." PP15 at 7-1. These statements indicate that EPA is considering membrane technologies as a basis for revisions to the ELGs. But, based on "significant information gaps and uncertainties" on the technological availability of membrane filtration, "critical uncertainties [] regarding operation of the suite of membrane filtration technologies that the Agency evaluated", "unacceptable non-water quality environmental impacts associated with management of the membranes' byproduct, brine", and "higher costs to industry", EPA rejected membrane technologies as BAT in the 2020 Rule. *See* 85 Fed. Reg. at 64,663 to 64,668.

UWAG continues to have serious concerns about the availability and economic achievability of membrane technology for the steam electric category. UWAG members are concerned that membranes cannot be employed at many facilities based on problems managing the brine produced by membranes and the high costs of installing and operating such systems. For example, there is little research demonstrating available methods to manage the brine produced by membrane treatment systems. Paste encapsulation is one process that is being evaluated; however, it is an emerging technology, and research has not demonstrated that it could be applied at the commercial scale nationwide. Significant questions about paste encapsulation include, for example, the amount of fly ash necessary to encapsulate the facility's volume of brine (*i.e.*, a site's material balance); how the encapsulated material will be mixed, transported, and placed; and whether the landfill can be managed to ensure long-term stability. UWAG's comments on the 2020 Rule expanded on these concerns and are incorporated here by reference.[7] If EPA pursues membrane technology as part of a new rulemaking, there are issues associated with solidifying and disposing of the brine that EPA should take into account. For example, facilities that currently sell fly ash will likely need to forgo all or a portion of that revenue to incorporate additional fly ash into the encapsulation mix. Other facilities may not produce enough fly ash during standard operations and may need to purchase supplemental fly ash, lime, or concrete.[8]

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[7] *See* UWAG Comments on EPA's Proposed Rule: Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category, at 72-83 (Jan. 21, 2021) (Comment ID: EPA-HQ-OW-2009-0819-8456).

[8] The PP15 docket provides technology summaries prepared by EPA, including a membrane technology summary that briefly lists "[c]oncentrate management equipment" as a cost consideration. The membrane technology summary does not fully address the numerous site-specific factors that limit nationwide applicability of membranes and management of associated brine or concentrate. Furthermore, the discussion of Non-Water Quality Environmental Impacts (NWQEI) appears to overlook the uncertainty surrounding disposal of concentrated brine or paste. Accordingly, EPA's review of membranes should include detailed considerations of cost and NWQEIs.

EPA's conclusions in the 2020 Rule that membrane filtration is not BAT for existing sources was correct. UWAG urges EPA to carefully consider both the fitness of membrane filtration for FGDW and whether brine produced from membrane treatment systems can be safely and cost-effectively managed.

UWAG appreciates your consideration of these comments.

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EXHIBIT 11



United States
Environmental Protection
Agency

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

April 2024

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U.S. Environmental Protection Agency
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EPA-821-R-24-004

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List of Abbreviations

ACE	Affordable Clean Energy
BA	bottom ash
BAT	best available technology economically achievable
BCA	Benefit and Cost Analysis
BMP	best management practice
BOD	biochemical oxygen demand
CA	combined ash
CAA	Clean Air Act
CBI	confidential business information
CCR	coal combustion residuals
CFR	Code of Federal Regulations
CH_4	methane
CO_2	carbon dioxide
CP	chemical precipitation
CPP	Clean Power Plan
CRL	combustion residual leachate
CSAPR	Cross-State Air Pollution Rule
CSC	compact submerged conveyor
CUR	capacity utilization rates
CWA	Clean Water Act
CWT	centralized waste treatment
DOE	Department of Energy
EA	Environmental Assessment

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EDR	electrodialysis reversal
EGU	electric generating unit
EIA	Energy Information Administration
EJA	Environmental Justice Analysis
ELGs	effluent limitations guidelines and standards
EPA	U.S. Environmental Protection Agency
EPRI	Electric Power Research Institute
FA	fly ash
FBR	fluidized bed reactor
FGD	flue gas desulfurization
FGMC	flue gas mercury control
FO	forward osmosis
gal	gallon
GHG	greenhouse gas
GPD	gallons per day
GPM	gallons per minute
HAP	hazardous air pollutant
HRR	high recycle rate
HRT	hydraulic residence time
HRTR	high residence time reduction
HVAC	heating, ventilation, and air conditioning
ICR	information collection request
IPM	Integrated Planning Model
kWh	kilowatt-hour
L	liter
lb	pound
LRTR	low residence time reduction
LUEGU	low utilization electric generating unit
MATS	Mercury and Air Toxics Standards

MDS	mechanical drag system
mg	milligrams
MGD	million gallons per day
MGY	million gallons per year
mi	mile
µg	micrograms
MW	megawatts
MWh	megawatt-hours
N_2O	nitrous oxide
NA	not applicable
NAAQS	National Ambient Air Quality Standards
NERC	North American Electric Reliability Corporation
NOPP	notice of planned participation
NO_X	oxides of nitrogen
NPDES	National Pollutant Discharge Elimination System
NSPS	new source performance standards
NWQEI	non-water quality environmental impacts
O&M	operation and maintenance
OLEM	Office of Land and Emergency Management
ORCR	Office of Resource Conservation and Recovery
PM	particulate matter
POTW	publicly owned treatment works
PSES	pretreatment standards for existing sources
PSNS	pretreatment standards for new sources
QA	quality assurance
QC	quality control
RCRA	Resource Conservation and Recovery Act
RIA	Regulatory Impact Analysis
RO	reverse osmosis

SDE	spray dryer evaporator
SO_2	sulfur dioxide
TCLP	toxicity characteristic leaching procedure
TDD	Technical Development Document
TDS	total dissolved solids
TMT	trimercapto-s-triazine
TPY	tons per year
TSS	total suspended solids
VIP	Voluntary Incentives Program
WOTUS	Waters of the United States
ZVI	zero valent iron

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5. Engineering Costs

For the 2024 final rule, the U.S. Environmental Protection Agency (EPA) estimated compliance costs for flue gas desulfurization (FGD) wastewater; bottom ash (BA) transport water; combustion residual leachate (CRL) from landfills and surface impoundments; and legacy wastewater. These estimates further develop the estimated costs from the 2015 and 2020 rules. Section 9 of the 2015 TDD presents the EPA's methodology for estimating compliance costs for FGD wastewater, BA transport water, and CRL. Section 5 of the 2020 Supplemental TDD describes the EPA's cost estimates for FGD wastewater and BA transport water. Here, the EPA is presenting cost estimates for baseline compliance, post-compliance, and incremental costs, defined as follows:

- *Baseline compliance costs.* The EPA based its analysis on a modeled baseline that reflects the full implementation of the 2020 rule, the expected effects of announced retirements and fuel conversions, and the impacts of relevant final rules affecting the power sector. As such, the baseline appropriately includes the costs of achieving the 2020 rule limitations and standards, and the policy cases show the impacts resulting from changes to the existing 2020 limitations and standards. For more information, see the *Regulatory Impact Analysis for Final Supplemental Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category* (RIA) (U.S. EPA, 2024g). For FGD wastewater and BA transport water, the baseline compliance costs anticipate that plants will have met the requirements of the 2020 rule; for CRL and legacy wastewater, baseline compliance costs consider current treatment in place.
- *Post-compliance costs*. Post-compliance costs are costs for plants to comply with effluent limitations based on the technologies considered in the 2024 rule technology options. The EPA estimated post-compliance costs with the expectation that all steam electric power plants subject to the requirements of the 2024 rule will install and operate wastewater treatment and pollution prevention technologies equivalent to the technology bases for the regulatory options.
- *Incremental costs*. Incremental costs reflect the difference between the baseline compliance costs and 2024 rule post-compliance costs for each regulatory option.

The EPA's compliance cost estimates include the following components:

- *Capital costs (one-time costs).* Capital costs comprise the direct and indirect costs associated with purchasing, delivering, and installing pollution control technologies. Capital cost elements include purchased equipment and freight, equipment installation, buildings, site preparation, engineering costs, construction expenses, contractor's fees, and contingencies.
- *Annual operation and maintenance (O&M) costs (incurred every year).* Annual O&M costs comprise all costs related to operating and maintaining the pollution control technologies for a period of one year. O&M cost elements include costs associated with operating labor, maintenance labor, maintenance materials (routine replacement of equipment due to wear and tear), chemical purchases, energy requirements, residuals disposal, and compliance monitoring.
- *Other one-time or recurring costs.* In some cases, the technology options may also result in costs that recur less often than annually (*e.g.,* three-year recurring costs for equipment replacement) or one-time costs other than capital investment (*e.g.,* one-time cost to consult with an engineer).

The EPA updated its industry profile as follows:

- The EPA began by updating its profile to reflect retirements of electric generating units (EGUs) that will occur by December 31, 2028, for the FGD wastewater and BA transport water populations.
- The EPA also removed any EGUs that will have converted to a non-coal fuel source by December 31, 2028, for FGD wastewater and BA transport water populations.

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- Through August 2023, the EPA incorporated notices of planned participation (NOPPs) for any plants that opted into the Voluntary Incentives Program (VIP) for FGD wastewater.
- For CRL, the EPA removed plants that retired all coal-fired EGUs by December 31, 2023. The EPA did not remove EGUs that converted to different fossil fuel sources (*e.g.,* gas-fired) from the CRL population. These EGUs, which previously burned coal and generated coal combustion residuals (CCRs) that were disposed of in landfills and surface impoundments, remained in the population because the corresponding plant is still operating. The EPA updated its industry profile to include plants operating coal-fired EGUs or refueled EGUs that have an open or closed (retired) waste management unit (*i.e.,* landfill or surface impoundment) that discharges CRL.[26] Based on the applicability of 40 CFR 423, these plants and CRL are still subject to the guidelines. See Section 5.3.1 for details on how the EPA developed the CRL population.
- The EPA incorporated retired and operating plants with surface impoundments that are open (*i.e.,* have not initiated the closure process under the CCR regulations) using information from the Office of Land and Emergency Management (OLEM) and power company CCR websites, as described in Section 2.5.

The remainder of this section describes the EPA's methodology for estimating baseline compliance costs, post-compliance costs, and incremental costs by wastestream, as well as industry-level compliance costs for the 2024 rule.

5.1 FGD Wastewater

For the 2024 final rule, the EPA estimated costs for plants to install and operate four technologies: chemical precipitation followed by low residence time reduction (CP+LRTR), membrane filtration, spray dryer evaporator (SDE), and thermal evaporation.

For CP+LRTR, the EPA included the following treatment components for FGD wastewater, consistent with the 2020 rule methodology:

- CP treatment equipment (equalization and storage tanks, pumps, reaction tanks, solids-contact clarifier, and gravity sand filter).
- CP chemical feed systems (lime, organosulfide, ferric chloride, and polymers).
- LRTR treatment equipment (anoxic/anaerobic bioreactor, flow control, backwash supply, and storage tanks).
- LRTR chemical feed system for nutrients.
- Pretreatment system for nitrate/nitrite (for plants with nitrate/nitrite concentrations above 50 milligrams per liter [mg/L]).
- Heat exchanger.
- Ultrafilter.
- Compliance monitoring (including sample collection and analysis).
- Solids handling (sludge holding tank and filter press).
- Transportation and disposal of solids in a landfill.

[26] For a new subcategory of CRL, the EPA identified potential discharges of unmanaged CRL, which the EPA is defining in this rule to mean the following: (1) discharges of CRL that the permitting authority determines are the functional equivalent of a direct discharge to Waters of the United States (WOTUS) through groundwater, or (2) discharges of CRL that has leached from a waste management unit into the subsurface and mixed with groundwater prior to being captured and pumped to the surface for discharge directly to a WOTUS.

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For membrane filtration, the EPA included the following FGD wastewater treatment components, consistent with the 2020 rule methodology:

- CP treatment equipment (equalization and storage tanks, pumps, reaction tanks, solids-contact clarifier, and gravity sand filter).
- CP chemical feed systems (lime, organosulfide, ferric chloride, and polymers).
- Membrane filtration treatment equipment (membrane filtration, reverse osmosis [RO], and storage tanks).
- Additional fly ash (FA) purchase (if plant was identified as having an FA deficit).[27]
- Brine encapsulation.
- Transportation and disposal of solids in a landfill.

For SDE, the EPA included the following FGD wastewater treatment components:

- Pretreatment using membrane filtration (for flows greater than 150 gallons per minute [GPM] only) (includes membrane filtration, RO, and storage tanks).
- SDE equipment.
- Transportation and disposal of solids in a landfill.

For thermal evaporation treatment of FGD wastewater, the EPA included the following treatment components:

- Membrane filtration treatment equipment (for preconcentration, as needed).
- Brine concentration and encapsulation or crystallization equipment.
- Transportation and disposal of solids in a landfill.

Section 5.1.1 describes the cost inputs and the methodology for updating the FGD wastewater flow rates from the 2020 rule. Sections 5.1.2, 5.1.3, 5.1.4, and 5.1.5 present the EPA's methodology for estimating costs for LRTR, membrane filtration, SDE, and thermal evaporation, respectively. Section 5.1.6 presents the EPA's methodology for determining the least cost zero-discharge technology option for FGD wastewater.

5.1.1 FGD Cost Calculation Inputs

To estimate plant-level baseline and post-compliance costs of implementing FGD wastewater treatment technologies, the EPA developed cost calculation databases. These databases combine plant-specific input values, including wastewater flow rates and baseline treatment technology, with the relationships between costs and FGD flow rates described in Sections 5.1.2, 5.1.3, and 5.1.4 to estimate baseline and post-compliance costs for each plant (ERG, 2024, 2024a). For the 2024 final rule, the EPA used input data compiled from the 2015 and 2020 rules—including Steam Electric Survey data, site visits, sampling episodes, and other industry-provided data—and updated these data using new information gathered from industry (see Section 2). This section describes the updates to cost inputs from the 2020 rule.

Population

The EPA identified coal-fired power plants that discharge FGD wastewater to surface water or a publicly owned treatment works (POTW) and that are not expected to retire or convert fuel sources by December 31, 2028. The EPA started with the population of plants from the 2020 rule and updated the population based on industry-provided data and new publicly available data on operational changes. The EPA also

[27] Refer to the *2024 Steam Electric Supplemental Final Rule: Fly Ash Analysis* memorandum for more information (U.S. EPA, 2024h).

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compiled a list of the EGUs at these plants that discharge FGD wastewater, keeping in mind that some plants retire or convert individual EGUs and not the entire plant.

Flow Rate

For each plant, the EPA estimated two FGD wastewater flow rates: the FGD purge flow rate (the typical amount of wastewater from the FGD scrubber that is sent to FGD wastewater treatment) and the FGD optimized flow rate (a rate that considers a reduction in FGD wastewater purged from the system, where equipment metallurgy is able to accommodate increased chloride concentration in the FGD system). As in the 2020 rule, the EPA used the FGD purge flow rate to calculate capital costs to ensure that the installed treatment technologies would be able to accommodate the maximum possible FGD flow. The EPA also concluded that plants would optimize the FGD purge flow rate to reduce the flow that must be treated, and thereby reduce overall O&M compliance costs. As flows are recycled through the FGD system, chloride concentrations increase; therefore, when calculating an optimized flow rate, the EPA considered plant-specific constraints such as maximum design chloride concentrations and operating chloride concentrations for the FGD systems.

For the 2024 rule, the EPA largely used plant-specific FGD wastewater flows consistent with the 2020 rule (U.S. EPA, 2020). The EPA identified some facilities where changes to plant operations warranted updates to FGD wastewater flow rates. At plants where some, but not all, EGUs were designated for retirement or fuel conversion before December 31, 2028, the EPA adjusted FGD wastewater flow rates (purge and optimized) to remove flow for these EGUs. The EPA also incorporated any flow rate updates received in the 2023 proposed rule public comments. Refer to the *Flue Gas Desulfurization Flow Methodology for Compliance Costs and Pollutant Loadings – 2024 Final Rule* memorandum for a summary of these updates (U.S. EPA, 2024i).

Baseline Treatment Technology

For this cost analysis, the EPA assumed that plants subject to the FGD wastewater discharge requirements in the 2020 rule would install the treatment technology basis defined for the 2020 rule. If a plant opted into the 2020 rule VIP, then the EPA assumed membrane filtration as the baseline treatment technology. For all other FGD wastewater discharges, the EPA assumed CP+LRTR baseline treatment technology. Table 8 outlines the baseline scenarios for the plants included in the EPA's 2024 analyses and the corresponding estimated compliance costs.

Table 8. 2024 Rule FGD Wastewater Technology Bases

2024 Technology Option Evaluated	2020 Rule Subcategory [a]	2024 Baseline Treatment Technology	Estimated Incremental Capital Compliance Cost	Estimated Incremental O&M Compliance Cost
Zero discharge	VIP	Membrane filtration	Costs are equal to zero	Costs are equal to zero
	All other FGD wastewater discharges	CP+LRTR	Costs for membrane filtration (no CP costs) or SDE	Costs for membrane filtration (no CP costs) or SDE, minus LRTR [b]

a—The EPA did not evaluate costs associated with the 2020 rule FGD high-flow subcategory because the one applicable plant is scheduled to retire its coal-fired EGUs by December 31, 2028.

b—The EPA estimated O&M costs as the incremental costs between operating and maintaining an LRTR system (see Section 5.1.2) and operating and maintaining a membrane filtration system (see Section 5.1.3) or SDE system (see Section 5.1.4). For the zero-discharge technology option, the EPA assumed plants will stop operating the LRTR portion of the system. The EPA also assumed that plants installing membrane filtration specifically will continue operating the CP portion as pretreatment.

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Landfill Data

The EPA used data from the Steam Electric Survey and public permit data to determine if each plant in the FGD wastewater population has a lined CCR landfill (active or inactive) for disposal of treatment residuals. For the 2024 final rule, the EPA updated this information to match the population used for CRL costs (see Section 0 for more information). Plants identified as having a landfill incurred compliance costs for on-site transportation and disposal of treatment residuals; all other plants incurred compliance costs for off-site transportation and disposal.

5.1.2 Cost Methodology for LRTR

As described in the RIA, the EPA's baseline appropriately includes the costs of achieving the 2020 rule limitations and standards, and the policy cases show the impacts resulting from changes to the existing 2020 limitations and standards. Therefore, the EPA assumed that plants have come into compliance with the 2020 rule, and all plants in the 2024 final rule analysis are assumed to have installed CP+LRTR, membrane filtration, or equivalent treatment. Since both technology bases include CP, the EPA did not estimate additional compliance costs for CP treatment. Further, since the EPA assumes that all plants that did not opt into the 2020 rule VIP have installed LRTR, no plants will incur incremental capital costs to install this technology. The EPA incorporated LRTR O&M as a cost savings for the zero-discharge technology option for non-VIP plants.

The EPA updated the LRTR O&M cost curves by adjusting the cost indexing values to 2023 dollars using data from the RSMeans Historical Cost Index (RSMeans, 2023). The 2021 cost index value was 238.3, and the 2023 cost index value was 318.8. The EPA multiplied the cost curve components by the ratio of these indexes (the 2023 index divided by the 2021 index equals 1.338), resulting in the equations presented below. To determine plant-specific nitrate/nitrite concentrations and consequently which LRTR cost curve to use, the EPA used sampling data from the 2015 rule analytical database (ERG, 2015, 2015a) and the Steam Electric Survey (U.S. EPA, 2015). Plants with nitrate/nitrite concentrations above 50 mg/L in untreated FGD wastewater require nitrate/nitrite pretreatment and are considered "high nitrates."

The resulting adjusted cost curves are as follows:

$$\text{LRTR O\&M cost – low nitrates (2023\$/year)} = 1.08 \times \text{FGD flow (gallons per day [GPD])} + 479{,}404$$

$$\text{LRTR O\&M cost – high nitrates (2023\$/year)} = 1.61 \times \text{FGD flow (GPD)} + 506{,}970$$

Similar to the 2020 and 2015 rules, the EPA estimated compliance monitoring costs to account for sampling labor and materials as well as the costs associated with sample preservation, shipping, and analysis for the pollutants selected for regulation (arsenic, mercury, nitrate/nitrite, and selenium for CP+LRTR). The EPA also updated the compliance monitoring cost to 2023 dollars, resulting in an amount of $110,968 for each plant.

The EPA estimated LRTR plant-level O&M cost savings as follows:

- For plants opting in to the 2020 rule VIP, the EPA estimated zero cost savings.
- For one plant that installed a CP system capable of meeting the 2020 rule's best available technology economically achievable (BAT) limitations, the EPA estimated LRTR O&M cost savings as compliance monitoring only ($110,968).
- For all other plants, the EPA estimated LRTR O&M cost savings using the LRTR O&M cost equations described above with the plant-specific FGD optimized flow rate.

5.1.3 Cost Methodology for Membrane Filtration

As with the LRTR cost methodology, the EPA did not estimate additional costs for CP pretreatment for the membrane filtration cost methodology, as plants are assumed to have come into compliance with the

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2020 rule and already have this treatment in place. The EPA updated the membrane filtration cost curves by escalating them to 2023 dollars using the method described in Section 5.1.2.

The resulting curves are as follows:

membrane filtration capital cost with on-site transport/disposal (2023$) = 57.2 × FGD flow (GPD) + 2,388,069

membrane filtration O&M cost with on-site transport/disposal (2023$/year) = 8.41 × FGD flow (GPD) + 681,426

membrane filtration capital cost with off-site transport/disposal (2023$) = 52.8 × FGD flow (GPD) + 2,438,706

membrane filtration O&M cost with off-site transport/disposal (2023$/year) = 16.9 × FGD flow (GPD) + 681,825

In addition, plants that indirectly discharge receive an O&M cost savings for no longer paying annual fees for a POTW to accept and treat their FGD wastewater. The EPA identified one plant in the FGD wastewater population as an indirect discharger and assigned this plant $1.5M in O&M cost savings, the cited discharge fees in the utility's comment letter (EPA-HQ-2009-0819-10083-A1).

The EPA used the following equations to estimate the amount of brine and lime or other fillers to be disposed of, based on the EPA's *2024 Steam Electric Supplemental Final Rule: Fly Ash Analysis* (U.S. EPA, 2024h):

brine (tons) = brine flow (GPD) × density of brine (lb/gal) × 365 (days/year) × 0.0005 (ton/lb)

Where:

brine flow	=	FGD optimized flow (GPD) times brine production rate, 30%.
density of brine	=	8.84 pounds per gallon (lb/gal).

lime or other fillers (tons) = brine (tons) × ratio of lime or other fillers to brine

Where:

ratio of lime or other fillers to brine	=	Ratio by mass percentage of lime or other fillers to brine in encapsulation recipe, 0.28.

The EPA then summed the total solids for disposal as the following:

solids for disposal (tons) = brine (tons) + lime or other fillers (tons)

To estimate compliance costs for transporting and disposing of these solids, the EPA used equations from the 2015 rule and escalated them to 2023 dollars. For the on-site transportation capital cost and on-site disposal O&M cost equations, the EPA used RSMeans indexes to escalate from 2009 dollars with a ratio of 1.747; for all other transportation and disposal cost equations, the EPA used RSMeans indexes to escalate from 2011 dollars with a ratio of 1.717 (RSMeans, 2023). Because the membrane filtration capital and O&M cost curves already include transportation and disposal costs, the EPA subtracted out a percentage of transportation and disposal costs to avoid double counting. To protect confidential business information (CBI), the EPA estimated this amount as 25 percent.

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The resulting equations are as follows:

transportation capital cost (on-site) (2023$) = $50.40 × solids for disposal (tons) × 0.75

transportation O&M cost (on-site) (2023$/year) = $5.59 × solids for disposal (tons) × 0.75

disposal O&M cost (on-site) (2023$/year) = $14.04 × solids for disposal (tons) × 0.75

transportation O&M cost (off-site) (2023$/year) = $15.85 × solids for disposal (tons) × 0.75

disposal O&M cost (off-site) (2023$/year) = $70.37 × solids for disposal (tons) × 0.75

For any plants with an FA deficit, as described in the *2024 Steam Electric Supplemental Final Rule: Fly Ash Analysis* (U.S. EPA, 2024h), the EPA supplemented the membrane filtration costs with the cost to purchase additional FA on an annual basis using the deficit of ash in tons: $35.49/ton. For plants with this FA deficit, the EPA also supplemented the transportation and disposal costs for brine and lime or other fillers with the cost to transport and dispose of this additional FA, using the equations described above with a factor of 1 (instead of 0.75).

In the 2024 final rule, the EPA is providing one year of flexibility to allow for membrane filtration permeate discharge as long as the plant reports monitoring data to a publicly available website. Refer to the *Membrane Monitoring Cost Methodology* and the *Membrane Recordkeeping and Reporting Cost Methodology* for additional information (U.S. EPA, 2024j, 2024k). The one-time plant-level cost would apply during the first year of membrane filtration operation, for a total of $152,374.

The EPA estimated plant-level membrane filtration costs as follows:

- For plants opting in to the 2020 rule VIP, the EPA estimated zero capital, zero O&M, and zero one-time costs.
- For all other plants with FGD wastewater discharges, the EPA estimated plant-specific capital, O&M, and one-time costs.
    - The EPA estimated capital costs for membrane filtration using the capital cost equations described above and the FGD purge flow rate. The EPA also estimated transportation capital costs (on-site only) using the FGD purge flow rate and summed this with the membrane filtration capital cost (where applicable).
    - The EPA estimated O&M costs as the difference between LRTR O&M costs and membrane filtration O&M costs, using the FGD optimized flow rate. All plants are assumed to be currently operating LRTR systems that they will replace with membrane systems for this technology option. To estimate this difference, the EPA estimated LRTR O&M costs using the equations in Section 5.1.2 and estimated membrane O&M costs using the equations discussed in this section (including transportation and disposal O&M costs and FA purchase O&M costs). O&M costs for the membrane filtration technology option were calculated as the difference between LRTR and membrane filtration values. The EPA also accounted for O&M cost savings for the one indirect discharger identified.
    - The EPA estimated the same one-time cost for all plants for monitoring and recordkeeping ($152,374).

5.1.4 Cost Methodology for SDE

The EPA identified several vendors using a similar type of technology to evaporate wastewater by spraying fine misted wastewater into hot gases. The EPA solicited information including costs, performance data, and treatment system configuration details from Heartland, General Electric, Mitsubishi, and Ljungström. Using data from each vendor, the EPA developed separate relationships for capital costs (*e.g.,* purchased equipment and freight, equipment installation, buildings, site preparation,

engineering costs, construction expenses, contractor's fees, and contingency) and O&M costs (*e.g.,* operating labor, maintenance labor, maintenance materials, chemical purchases, energy requirements, and residuals disposal). The EPA developed comparable costs for the technologies for all vendors by evaluating the cost data provided by each vendor and augmenting those data with costs for missing components. See the *Spray Dryer Evaporator Cost Methodology* for a summary of the vendor-specific data (U.S. EPA, 2022b).

Based on feedback from SDE vendors, it is generally more cost effective to implement volume reduction (i.e., membrane filtration pretreatment) on wastewater streams above 200 GPM. As well, some vendors noted that some costs were only valid up to 150 GPM; therefore, the EPA estimated costs for spray evaporation only for small wastewater flows (≤ 150 GPM) and costs for volume reduction followed by spray evaporation for larger flows (>150 GPM). For each vendor, the EPA estimated both capital and O&M costs of an SDE treatment system over a range of FGD wastewater flows, from 0.69 GPM to 1,000 GPM. Consistent with feedback from vendors, the SDE treatment system for flows from 0.69 GPM to 150 GPM included only SDE and solids handling, while the SDE treatment system for flows from greater than 150 GPM to 1,000 GPM included preconcentration using membrane filtration followed by spray evaporation treatment of the brine.

Based on values from all four vendors at various flows within the range, the EPA calculated the average cost for capital and O&M costs. See Section 3 of the *Spray Dryer Evaporator Cost Methodology* for a summary of average costs by flow (U.S. EPA, 2022b). The EPA used the line of best fit derived from these average cost data points to develop capital and O&M cost equations based on wastewater flow (refer to Section 4 of the *Spray Dryer Evaporator Cost Methodology*). The EPA then escalated these cost equations from 2021 to 2023 dollars using a factor of 1.338.

The resulting equations are as follows:

Capital and O&M costs assuming on-site solids management for flows up to 150 GPM:

spray evaporation with on-site solids management – capital costs (2023$) = 128 × flow (GPD) + 14,717,560

spray evaporation with on-site solids management – O&M costs (2023$/year) = 12.1 × flow (GPD) + 144,207

Capital and O&M costs assuming off-site solids management for flows up to 150 GPM:

spray evaporation with off-site solids management – capital costs (2023$) = 124 × flow (GPD) + 14,717,560

spray evaporation with off-site solids management – O&M costs (2023$/year) = 18.1 × flow (GPD) + 144,207

Capital and O&M costs assuming on-site solids management for flows between 150 and 1,000 GPM:

membrane filtration followed by spray evaporation with on-site solids management – capital costs (2023$) = 77.2 × flow (GPD) + 18,411,536

membrane filtration followed by spray evaporation with on-site solids management – O&M costs (2023$/year) = 10.2 × flow (GPD) + 843,692

Capital and O&M costs assuming off-site solids management for flows between 150 and 1,000 GPM:

membrane filtration followed by spray evaporation with off-site solids management – capital costs (2023$) = 69.4 × flow (GPD) + 18,462,172

membrane filtration followed by spray evaporation with off-site solids management – O&M costs (2023$/year) = 19.5 × flow (GPD) + 844,091

The EPA estimated plant-level SDE costs as follows:

- For plants opting in to the 2020 rule VIP, the EPA estimated zero capital and zero O&M costs.
- For all other plants with FGD wastewater discharges, the EPA estimated plant-specific capital and O&M costs.
  - The EPA estimated capital costs for SDE using the FGD purge flow rate. Where a plant-level purge flow was greater than 1,000 GPM, the EPA estimated costs for a separate SDE system at each EGU at the plant, using the unit-level purge flow rate along with the corresponding cost equation, and then summed the unit-level costs to the plant level.
  - The EPA estimated O&M costs as the difference between LRTR O&M costs and SDE O&M costs, using the FGD optimized flow rate. All plants are assumed to be currently operating LRTR systems that they will replace with SDE systems for this technology option. To estimate this difference, the EPA estimated LRTR O&M costs using the equations in Section 5.1.2 and estimated SDE O&M costs using the equations discussed in this section. O&M costs for the SDE technology option were calculated as the difference between LRTR and SDE values. Where the plant-level purge flow was greater than 1,000 GPM, the EPA also estimated costs for separate SDE systems at each EGU at the plant, using the unit-level optimized flow rate along with the corresponding cost equation, and then summed the unit-level costs to the plant level.

5.1.5 Cost Methodology for Thermal Evaporation

As described in the *Flue Gas Desulfurization and Combustion Residual Leachate Thermal Evaporation Cost Methodology* memorandum, the EPA estimated plant-level thermal evaporation costs using average costs from two technology vendors (U.S. EPA, 2024l).

The resulting cost equations are as follows:

$$\text{thermal evaporation capital cost (2023\$)} = (\text{Vendor 1 capital cost} + \text{Vendor 2 capital cost}) \div 2$$

$$\text{thermal evaporation O\&M cost (2023\$/year)} = (\text{Vendor 1 O\&M cost} + \text{Vendor 2 O\&M cost}) \div 2$$

The EPA estimated plant-level thermal evaporation costs as follows:

- For plants opting in to the 2020 rule VIP, the EPA estimated zero capital and zero O&M costs.
- For all other plants with FGD wastewater discharges, the EPA estimated plant-specific capital and O&M costs.
  - The EPA estimated capital costs for thermal evaporation using the FGD purge flow rate.
  - The EPA estimated O&M costs as the difference between LRTR O&M costs and thermal evaporation O&M costs, using the FGD optimized flow rate. All plants are assumed to be currently operating LRTR systems that they will replace with thermal evaporation systems for this technology option. To estimate this difference, the EPA estimated LRTR O&M costs using the equations in Section 5.1.2 and estimated thermal evaporation O&M costs using the equations discussed in this section. O&M costs for the thermal evaporation technology option were calculated as the difference between LRTR and thermal evaporation values.

5.1.6 Cost Methodology for Zero Discharge

To estimate zero-discharge costs for FGD wastewater, the EPA compared the costs for membrane filtration (see Section 5.1.3) and SDE (see Section 5.1.4) for each plant and selected the least cost technology. Refer to the Least-Cost Technology by Plant (U.S. EPA, 2024m). The EPA did not consider thermal evaporation costs in its least cost option assessment because some of the costs are being treated as CBI, pursuant to claims made by technology vendors.

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EXHIBIT 12

EPRI Comments on Proposed Effluent Limitations Guidelines Rule

U.S. Environmental Protection Agency

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

Docket ID: EPA–HQ–OW–2009

40 CFR Part 423

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EXECUTIVE SUMMARY

The Electric Power Research Institute (EPRI) was established in 1973 as an independent, nonprofit center for public-interest energy and environmental research. EPRI brings together member organizations, the Institute's scientists and engineers, and other leading experts to work collaboratively on solutions to the challenges of electric power. These solutions span nearly every area of power generation, delivery, and use, including health, safety, and the environment.

EPRI is providing comments to the U.S Environmental Protection Agency (EPA) on the Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category, (referred to here as the "proposed revised Effluent Limitations Guidelines [ELG] rule") and on supporting information in docket EPA-HQ-OAR-2009-0819. The proposed revised ELG rule addresses three areas of the 2015 ELG rule—flue gas desulfurization (FGD) wastewater, combustion residual leachate (CRL), and bottom ash transport water (BATW). EPRI's comments focus on:

- Proposed best available technology (BAT) for FGD wastewater treatment (e.g., chemical precipitation, membranes, and brine management and encapsulation), including technical feasibility, capital cost, operating and maintenance costs, and pollutant reduction
- Proposed BAT for CRL wastewater treatment (chemical precipitation), including capital cost, operating and maintenance costs, and technical feasibility
- Potential stricter BAT for CRL wastewater treatment (membranes), including capital cost, operating and maintenance costs, and technical feasibility
- Proposed BAT for BATW that bans discharge from remote settling systems, focusing on technical feasibility

In 1996, EPRI initiated an effort to characterize plant wastewaters and to evaluate sampling and analytical techniques for low-level trace metals those wastewaters may contain. More recently, EPRI has conducted numerous studies to evaluate technologies for treatment of FGD wastewaters, including membrane treatment.

EPRI has evaluated CRL management through leachate characterization at dozens of combustion residual landfills across the country. EPRI has also researched treatment of CRL using chemical precipitation methods in bench-scale testing and in full-scale passive treatment systems.

EPRI has also assessed bottom ash handling options, working with more than 20 plants with high-recycle bottom ash systems to characterize water balance and management in near-closed loop systems. These results help EPRI and the industry better understand the needed operational flexibility of a purge option. As a result of these studies, EPRI has significant data and experience, which we are providing to EPA as technical input on the proposed ELG rule.

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EPRI conducted as thorough a review of the proposed rule, the underlying data, and technical support documents as the 60-day comment period would allow. As there were more than 2,000 supporting documents, EPRI was unable to provide a truly comprehensive review; instead, it focused attention and technical input on the areas of expertise described above.

Key Comments on FGD BAT Wastewater Treatment Technical Feasibility

EPA rule making does not reflect an accurate calculational methodology for fly ash requirements and ash availability to estimate the cost to manage the resultant brine from membranes. EPRI's research shows EPA's current methodology significantly underestimates the industrywide feasibility and applicability of chemical precipitation (CP), membrane treatment, and encapsulation.

Key comments related to the technical feasibility of industry-wide application of membrane filtration followed by encapsulation for FGD wastewater include the following:

- EPA's approach of estimating fly ash required for brine encapsulation is not accurate. EPRI estimates more than 10x the amount of fly ash required as the EPA estimate. EPRI presents detailed comments on factors to consider in estimating fly ash requirements.
- EPRI research shows the EPA's estimate of the quantity of fly ash produced is overestimated by approximately 20 percent. Using the actual site-specific Energy Information Administration (EIA) reported data for all 22 plants is more accurate than using a "rule-of-thumb".
- The loss of fly ash beneficial reuse and impacts to the existing beneficial use markets is being underestimated and undervalued.
- EPRI observes that achievable membrane performance in FGD wastewater applications has not been accounted for leading to a 10x underestimation of brine management requirements.
- The available information provided in the Docket does not provide the basis that a higher level of membrane performance can and has been achieved by other industries and in international installations. Specifically, the EPA should demonstrate that high membrane recoveries (greater than 80 percent) are feasible in FGD wastewater applications.
- The number of plants that will require additional technologies to achieve zero liquid discharge (ZLD) will be higher than EPA estimates. In EPRI's analyses, membrane treatment alone is unlikely to be sufficient for FGD wastewater management at most sites, and many sites would likely consider thermal evaporation either standalone or in a combination with membranes and encapsulation.
- Achieving ZLD will be challenging for many sites. Due to issues related to water balance and pollutant cycling in the ZLD system, an option to discharge would provide operational flexibility.
- Achieving ZLD of FGD wastewater will require more than half of industry plants to install crystallizers leading to increased operational challenges.

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Key Comments on FGD BAT Wastewater Treatment Cost

The EPA estimate for the total cost of implementing the BAT for proposed regulatory Option 3 based on chemical precipitation (CP), membrane filtration and brine encapsulation differs significantly from EPRI's estimates. EPRI's capital cost estimate is nine times higher than EPA's capital cost estimate for the same list of plants. EPRI's O&M cost estimate is more than 40 times higher than EPA's O&M cost estimate for the same list of plants. In evaluating the total annualized costs, EPRI's estimate of industry cost is more than 25 times higher than EPA's estimate. Cost estimating, flow rate, brine management and encapsulation estimates could be improved by considering the following:

- Use FGD peak flow to estimate capital costs.
- Use FGD purge flow to estimate O&M costs, instead of the optimized flow, for membrane filtration.
- Use membrane system recovery that can be consistently achieved. EPA has stated that 70 percent was "the average FGD wastewater recovery from the membrane treatment vendors." However, EPA appears to use a much higher recovery in its cost estimates.
- The cost and quantities of residual waste that would be generated for membrane filtration and encapsulation are significantly higher than the EPA estimates.
- Fly ash shortages will lead sites to experience challenges and significant costs to acquire or harvest additional fly ash, including excavation, transport and drying the harvested ash.

In addition, the following should be considered:

- EPA appears to have misreported the costs for six plants that plan to operate past 2032 and would be required to install membrane filtration and encapsulation systems.
- EPA has not adequately accounted for the higher costs for those plants that will retire or repower in less than 20 years.
- Many sites will incur costs that are inconsistent with EPA's estimated costs for chemical precipitation, membrane filtration and encapsulation. Fly ash availability and FGD purge flow and quality will ultimately drive plant decisions related to technologies required to achieve zero liquid discharge and associated costs. EPRI's estimate of the lowest cost option for ZLD is 6 times higher than EPA's cost estimate for the same list of plants.

Key Comments on FGD Wastewater Treatment Pollutant Reduction

EPA rule making fails to consider the following important factors to estimating the quantity of pollutant reduction achieved by implementing membranes as FGD BAT:

- Pollutant loading remaining in FGD water after treatment by the 2020 ELG BAT are mainly from pollutants with very low toxicity.
- Estimates of bromide in FGD water used are significantly above EPRI's experience, and thus significantly inflates total pollution reduction calculations.

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Key Comments on CRL BAT Wastewater Treatment Cost

EPRI's annualized cost estimate of CRL BAT (CP) for the industry is approximately 170 percent higher than EPA's estimate. This appears to be due to failing to consider:

- Use leachate peak flow rate as the basis for engineering design of CRL CP in capital cost calculation. This will produce a more accurate estimate of the capital cost needed to build a reliable chemical precipitation treatment system.
- Base industry-level regulatory option cost for CRL BAT on all regulated CRL sites rather than a subset of the industry.
- Annual O&M labor requirements.
- Unit cost per flow at closed landfills are higher than active sites.

Key Comments on CRL Proposed BAT Limits

- EPA has not provided CRL data to show that the proposed BAT limits are technically feasible.
- Existing FGD wastewater data are not adequately representative of potential CRL CP effluent water quality. Therefore, it is not appropriate to use FGD wastewater data to set limits for CRL.
- Meeting BAT limit with CP treatment of FGD water has not been fully characterized.
- Given that dissolved arsenic concentration in CRL is higher than the BAT limit in many plants, the ability of CP to achieve dissolved arsenic removals to meet the 8 µg/L arsenic limit is uncertain.
- Flexibility for landfills nearing closure could avoid the construction of a larger and more expensive system that would only operate for a relatively short period of time.

Key Comment on Leachate Alternative Costs – Membrane

- EPA solicited comments on alternative Combustion Residual Leachate (CRL) BATs, to this end, EPRI has developed a cost estimate for leachate treatment consisting of advanced membrane filtration with brine solidification (AMF + BS). EPRI's estimated cost to the industry is $761 million more for AMF + BS than EPRI's estimate of CP.
- EPRI's cost estimate of CP + membrane is 3.5 more costly than EPRI's estimate of CP alone.

Key Comments on Bottom Ash Transport Water Proposed BAT Limits

The ability to purge water from high rate recycle remote bottom ash systems provides operational flexibility while allowing a very small incremental increase in pollutants.

- EPA fails to account for the plant's low capacity factor and uses non-representative water quality data in calculating Merrimack water quality so as to not overestimate pollution reduction.
- Blowdown purge is recommended to provide significant operational flexibility.

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- EPA's cost estimate for the total cost to the industry to implement reverse osmosis to treat purge should be improved for accuracy as is, it underrepresents these costs significantly.
- Using reverse osmosis to manage purge from bottom ash systems will need brine encapsulation, requiring ash supply that is already challenged by FGD BAT.
- The blowdown purge banned in the 2023 proposed ELG BAT for BATW would provide operational flexibility while avoiding significant capital costs for water treatment/management.
- Allowing a purge still provides the majority of pollutant reduction that would be achieved by a complete ban.

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EPA's approach of estimating fly ash required for brine encapsulation should be modified to increase accuracy. EPRI estimates more than 11x the amount of fly ash required compared to the EPA estimate 1

EPA's approach overestimates the quantity of fly ash produced by approximately 20 percent. We recommend use of actual site-specific EIA-reported data for all 22 plants versus using a "rule-of-thumb" estimate to improve accuracy. 13

The loss of fly ash beneficial reuse and impacts to the existing beneficial use markets is undervalued. 17

EPA's approach to estimating fly ash required for brine encapsulation is not accurate. We observe that the current methodology, if not improved, would lead to a 10x underestimation of brine management requirements. 20

The available information provided in the Docket does not provide basis that a higher level of membrane performance can and has been achieved by other industries and in international installations. Specifically, the EPA should demonstrate that high membrane recoveries (greater than 80 percent) are feasible in FGD wastewater applications. 21

The number of plants that will require additional technologies to achieve zero liquid discharge (ZLD) will be higher than EPA estimates. EPRI's research shows membrane treatment alone is unlikely to be sufficient for FGD wastewater management at most sites, and many sites would likely consider thermal evaporation either standalone or in a combination with membranes and encapsulation. 26

Achieving ZLD will be challenging for many sites. Due to issues related to water balance and pollutant cycling in the ZLD system, an option to discharge would provide operational flexibility. 28

Achieving ZLD of FGD wastewater will require more than half of industry plants to install crystallizers leading to increased operational challenges 28

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2 FGD Wastewater BAT Treatment Costs **32**

EPA's cost estimate methodology for the total cost to the industry to implement the BAT for proposed regulatory option 3 based on chemical precipitation (CP), membrane filtration and brine encapsulation should be improved for accuracy; as

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is, it underrepresents these costs significantly. EPRI's capital cost estimate is 9 times higher than EPA's capital cost estimate for the same list of plants. Notably, EPRI's operations and maintenance (O&M) cost estimate is 43 times higher than EPA's O&M cost estimate for the same list of plants. In evaluating the total annualized costs, EPRI's estimate of industry cost is 27 times higher than EPA's estimate. Further, EPRI's assessment indicates that membrane filtration is not economically achievable, as the O&M cost alone for a single plant was estimated to be 22 percent of the power plant's total revenue. 32

EPA has significantly underestimated BAT costs for membrane filtration due to several key differences in flow rate, brine management, and encapsulation estimates. 39

FGD peak flow with equipment redundancy should be used to estimate capital costs. 39

FGD purge flow should be used instead of optimized flow to estimate membrane filtration O&M costs. 41

Membrane system recovery that can be consistently achieved should be used; EPA has stated that 70% was "the average FGD wastewater recovery from the membrane treatment vendors." However, it appears EPA uses a much higher recovery in its cost estimates. recovery in its cost estimates. 42

EPA has significantly underestimated the O&M costs associated with brine management and encapsulation using its current calculation methods. EPRI's site-specific O&M cost estimate for a single plant is 35 times higher than EPA's cost estimate. 46

Fly ash shortages will lead sites to experience challenges and significant costs to acquire or harvest additional fly ash, including excavation, transport, and drying the harvested ash. 52

EPA appears to have misreported the costs for six plants that plan to operate past 2032 and would be required to install membrane filtration and encapsulation systems. 53

EPA has not accounted for the higher costs for plants that will retire or repower in less than 20 years. 54

Many sites will incur costs that are inconsistent with EPA's estimated costs for CP, membrane filtration, and encapsulation. Fly ash availability and FGD purge flow and quality will ultimately drive plant decisions related to technologies required to achieve ZLD and associated costs. EPRI's estimate of the lowest cost option for ZLD is 6 times higher than EPA's cost estimate for the same list of plants. 57

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Pollutant loading remaining in FGD water after treatment by the 2020 ELG FGD BAT are mainly from pollutants with very low toxicity. 61

Estimates of bromide in FGD water used are significantly above EPRI's experience, and thus significantly inflate the total pollution reduction calculations dependent upon this estimate. 63

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EPRI's annualized cost estimate of CRL BAT (chemical precipitation) for the industry is approximately 170 percent higher than EPA's estimate. EPRI recommends that the EPA revise its estimate. 65

Use leachate peak flow rate as the basis for engineering design of CRL CP in its capital cost calculation. This will produce a more accurate EPA estimate of the capital cost needed to build a reliable chemical precipitation treatment system. 65

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Meeting BAT limit with CP treatment of FGD water has not been fully characterized. 72

Given that dissolved arsenic concentration in CRL is higher than the BAT limit in many plants, the ability of CP to achieve dissolved arsenic removals to meet the 8 µg/L arsenic limit is uncertain. 73

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EPA solicited comments on alternative Combustion Residual Leachate (CRL) BATs, to this end, EPRI has developed a cost estimate for leachate treatment consisting of advanced membrane filtration with brine solidification (AMF + BS). EPRI's estimated cost to the industry is $761 million more for AMF + BS than EPRI's estimate of CP, assuming 134 plants require BAT. 81

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EPA fails to account for the plant's low capacity factor and uses non-representative water quality data in in calculating Merrimack water quality so as to not overestimate pollution reduction. 84

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EPA's cost estimate for the total cost to the industry to implement reverse osmosis to treat purge should be improved for accuracy as is, it underrepresents these costs significantly. 86

Using reverse osmosis to manage purge from bottom ash systems will need brine encapsulation, requiring ash supply that is already challenged by FGD BAT. 86

The blowdown purge, which is banned in the 2023 proposed ELG BAT for BATW, would provide significant operational flexibility. Water balance issues have caused plants to purge water from BATW systems. 86

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2 FGD WASTEWATER BAT TREATMENT COSTS

EPA's cost estimate methodology for the total cost to the industry to implement the BAT for proposed regulatory option 3 based on chemical precipitation (CP), membrane filtration and brine encapsulation should be improved for accuracy; as is, it underrepresents these costs significantly. EPRI's capital cost estimate is 9 times higher than EPA's capital cost estimate for the same list of plants. Notably, EPRI's operations and maintenance (O&M) cost estimate is 43 times higher than EPA's O&M cost estimate for the same list of plants. In evaluating the total annualized costs, EPRI's estimate of industry cost is 27 times higher than EPA's estimate. Further, EPRI's assessment indicates that membrane filtration is not economically achievable, as the O&M cost alone for a single plant was estimated to be 22 percent of the power plant's total revenue.

In this rulemaking, EPA presented its methodology and estimated costs for plants generating flue gas desulfurization (FGD) wastewater after 2032 that would be required to install a zero liquid discharge (ZLD) system based on CP followed by membrane filtration and brine encapsulation to comply with preferred regulatory option 3 of the proposed rule. In developing costs for the industry, EPA provides the following cost basis [EPA, 2023a; EPA, 2023b; EPA, 2023c]:

- 25 plants plan to generate FGD wastewater after 2032 that would, therefore, be required to install a ZLD FGD wastewater treatment system based on membrane filtration [Table 4, EPA, 2023a]
- Three plants (Cross, Monroe, and Scherer) are designated as having opted into the 2020 voluntary incentives program (VIP) [Table 3, EPA, 2023a]. For these plants, EPA estimated zero capital and zero O&M costs. [EPA, 2023c]
- For the remaining 22 plants, EPA estimated capital costs for membrane filtration only. EPA did not estimate additional costs for CP pretreatment for the membrane filtration technology option, as plants are assumed to have come into compliance with the 2020 rule and already have this treatment in place. [EPA, 2023c]
- To estimate O&M costs for the 22 plants, EPA estimated the difference in costs between biological low residence time reduction (LRTR) and membrane filtration.

EPRI has taken a similar approach to generally align with EPA's cost basis:

- EPRI has developed cost estimates for each of the 22 plants that would be required to comply with regulatory option 3. EPRI has not developed costs for the three plants that opted into the VIP.

- Further, regardless of each plant's FGD wastewater treatment equipment currently in place, EPRI has adapted EPA's basis assuming that all 22 plants have already installed CP and biological treatment as a baseline for estimating capital costs.
- Therefore, the costs developed by EPRI consider the capital costs to convert each plant from CP and biological treatment to CP, membrane filtration, and brine encapsulation.
- EPRI has evaluated the total O&M costs associated with operating a CP, membrane filtration, and brine encapsulation system. To better compare EPRI's and EPA's cost estimates for this treatment system, EPRI is comparing its O&M estimate to EPA's estimated O&M costs for membrane filtration as presented in its FGD Wastewater Cost Database [EPA, 2023b] and not EPA's O&M cost estimate as reported in EPA's Generating Unit-Level Costs and Loadings Estimates by Regulatory Option for the 2023 Proposed Rule [EPA, 2023a]. The latter appears to show only the O&M cost difference between LRTR and membrane filtration as discussed by EPA [EPA, 2023c] and contains several errors in reported costs, which will be addressed later in these comments.

Even when using a similar approach and baseline costs, EPRI arrives at a much higher industrywide cost for CP, membrane filtration, and brine encapsulation compared to those costs developed by EPA. Table 2-1 compares costs developed by EPRI and the costs presented by EPA for the same industry profile of 22 plants. As shown, EPRI's capital cost estimate is 9 times higher than EPA's capital cost estimate. Even more, EPRI's O&M cost estimate is 43 times higher than EPA's O&M cost estimate. In evaluating total annualized costs, EPRI's estimate of industry cost is 27 times higher than EPA's estimate.

Table 2-1. Comparison of EPRI and EPA industry-wide cost estimates to convert from CP and biological treatment to CP, membrane filtration, and brine encapsulation

Source of Industry Cost[1]	Capital Cost ($M)	Annual O&M Cost ($M/yr)	Total Annualized Cost ($M/yr)[2]	Ratio EPRI/EPA Capital Cost	Ratio EPRI/EPA O&M Cost	Ratio EPRI/EPA Total Annual Cost
EPRI	5,410	2,783	3,292	9	43	27
EPA	613	65	122			

$M/yr = million dollars per year (2021 dollars)

1. Includes 22 plants that are assumed to operate past 2032 and therefore required to comply with regulatory option 3 BAT: CP, membrane filtration, with brine encapsulation. EPA cost shown in the summation of costs for 22 plants as presented in FGD Wastewater Proposed Rule Cost Database [EPA, 2023b].
2. Total annualized cost which is a sum of the annualized cost of capital (assumes 7% interest rate and 20-year life) and the annual O&M cost

Table 2-2 provides a comparison of EPRI and EPA cost estimates for each of the 22 plants that would be required to install membrane filtration and brine encapsulation technology in compliance with proposed regulatory option 3.

Table 2-2. Comparison of EPRI and EPA cost estimates for each plant to convert from CP and biological treatment to CP, membrane filtration and brine encapsulation

EPA ICR ID	Plant Name	EPRI Cost Estimate[1]			EPA Cost Estimate[1]		
		Capital Cost ($M)	O&M Cost ($M/yr)	Total Annualized Cost ($M)[2]	Capital Cost ($M)	O&M Cost ($M/yr)	Total Annualized Cost ($M)[2]
493	J. K. Spruce Power Plant	51	16	21	6	0.6	1.1
771	Kyger Creek Station	159	70	85	18	2.0	3.8
904	Muscatine	24	3	5	2	0.5	0.7
1236	Mitchell Plant	223	86	107	21	4.4	6.4
1381	Homer City	67	23	29	9	1.1	1.9
1674	Trimble County	726	432	500	73	10.8	17.7
2244	Plant Bowen	522	275	324	90	5.3	13.8
2601	Ghent	376	186	221	42	4.1	8.0
3265	Cardinal	610	335	392	65	5.3	11.5
3309	Lawrence Energy Center	38	10	14	2	0.5	0.7
3464	W. A. Parish E.G.S.	49	15	20	6	0.9	1.4
3604	Mill Creek	112	44	55	13	1.5	2.7
5318	Clifty Creek Station	221	106	127	27	2.8	5.3
6334	Leland Olds Station	106	36	46	10	1.2	2.2
6377	Big Bend Station	641	396	456	64	6.5	12.5
7785	Seminole Generating Station	139	57	70	15	1.8	3.2
8353	Jeffrey Energy Center	268	142	167	33	2.7	5.8
8965	F.B. Culley Generating Station	117	55	66	8	0.8	1.5
9161	John E. Amos Plant	601	362	418	80	7.0	14.5
9225	Fort Martin Power Station	119	33	44	13	1.8	3.0

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EPA ICR ID	Plant Name	EPRI Cost Estimate[1]			EPA Cost Estimate[1]		
		Capital Cost ($M)	O&M Cost ($M/yr)	Total Annualized Cost ($M)[2]	Capital Cost ($M)	O&M Cost ($M/yr)	Total Annualized Cost ($M)[2]
9971	Dallman	86	29	37	5	0.8	1.2
56068	Elm Road Generating Station	158	72	87	15	2.4	3.8
TOTAL		5,410	2,783	3,292	613	65	122

ICR = Information Collection Request

$M/yr = million dollars per year (2021 dollars)

1. Includes 22 plants that are assumed to operate past 2032 and therefore required to comply with regulatory option 3 BAT: CP, membrane filtration, with brine encapsulation. EPA cost shown in the summation of costs for 22 plants as presented in FGD Wastewater Proposed Rule Cost Database [EPA, 2023b].
2. Total annualized cost which is a sum of the annualized cost of capital (assumes 7% interest rate and 20-year life) and the annual O&M cost

Table 2-1 and Table 2-2 show that the largest disparity between EPRI's and EPA's costs exists in the O&M cost estimates. As discussed in Section 1, a significant reason for the O&M cost difference appears to be largely attributed to EPA's approach in underestimating brine management requirements and associated costs. Figure 2-1 shows EPRI's estimate of CP, membrane filtration, and brine encapsulation costs and the relative contribution of annualized capital cost versus annual O&M costs for each of the 22 plants that would be required to comply with regulatory option 3. As seen in this figure, the annual O&M cost estimate for each plant is approximately 3 to 6 times higher than the annualized capital cost estimate for each plant.

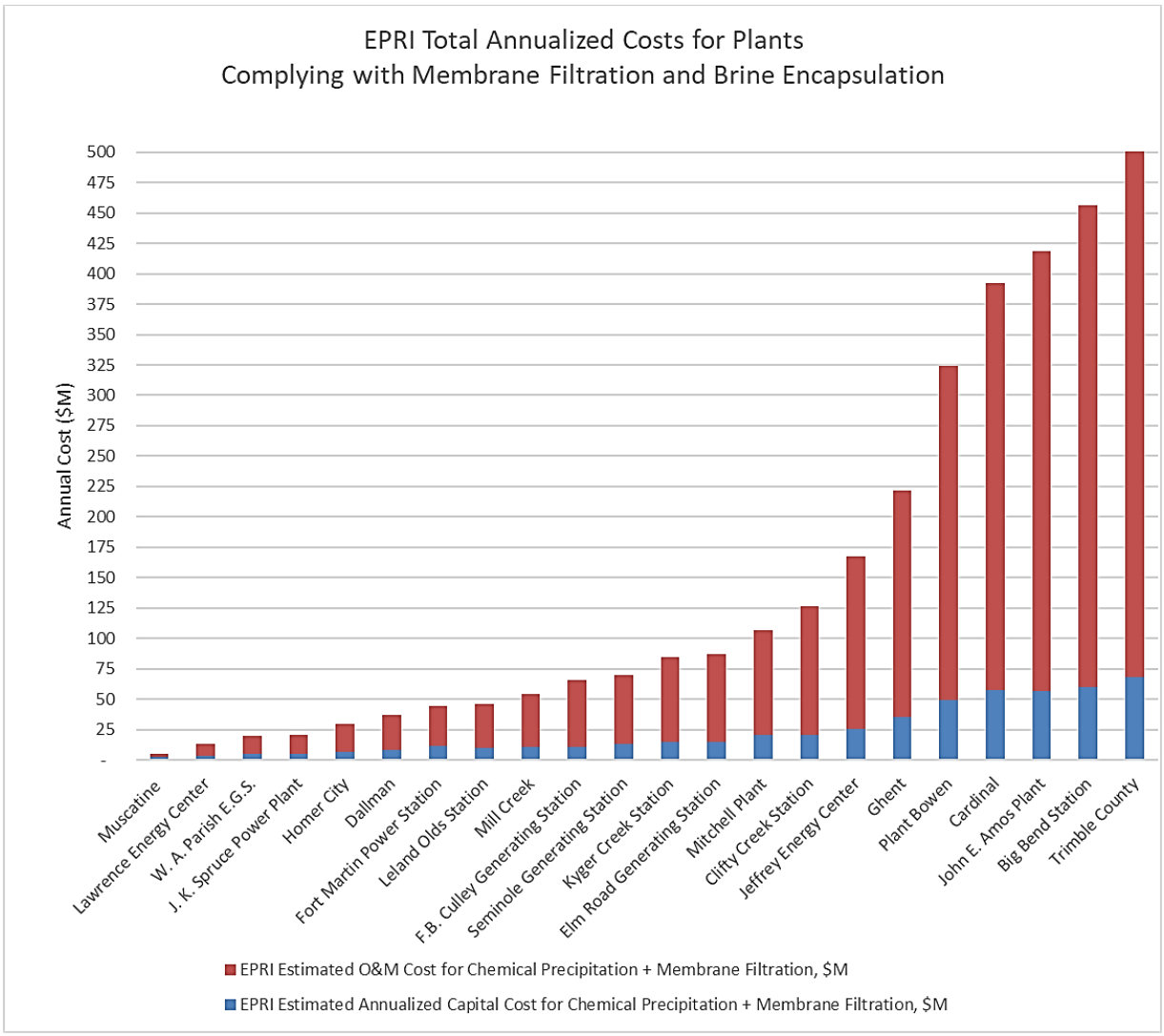


Figure 2-1. EPRI estimate of total annualized costs for 22 plants complying with BAT regulatory option 3: CP, membrane filtration, and brine encapsulation, 2021$

In comparison, EPA's estimate of CP, membrane filtration, and brine encapsulation costs and the relative contribution of capital cost versus annual O&M costs for each of the 22 plants (Figure 2-2) indicate that the annual O&M cost estimate for each plant is similar to the annualized capital cost estimate for each plant. Figure 2-2 shows the significant difference in EPA's costs in terms of the relative capital and O&M costs, and illustrates that EPA's costs are 1 to 2 orders of magnitude lower than EPRI's cost estimates.

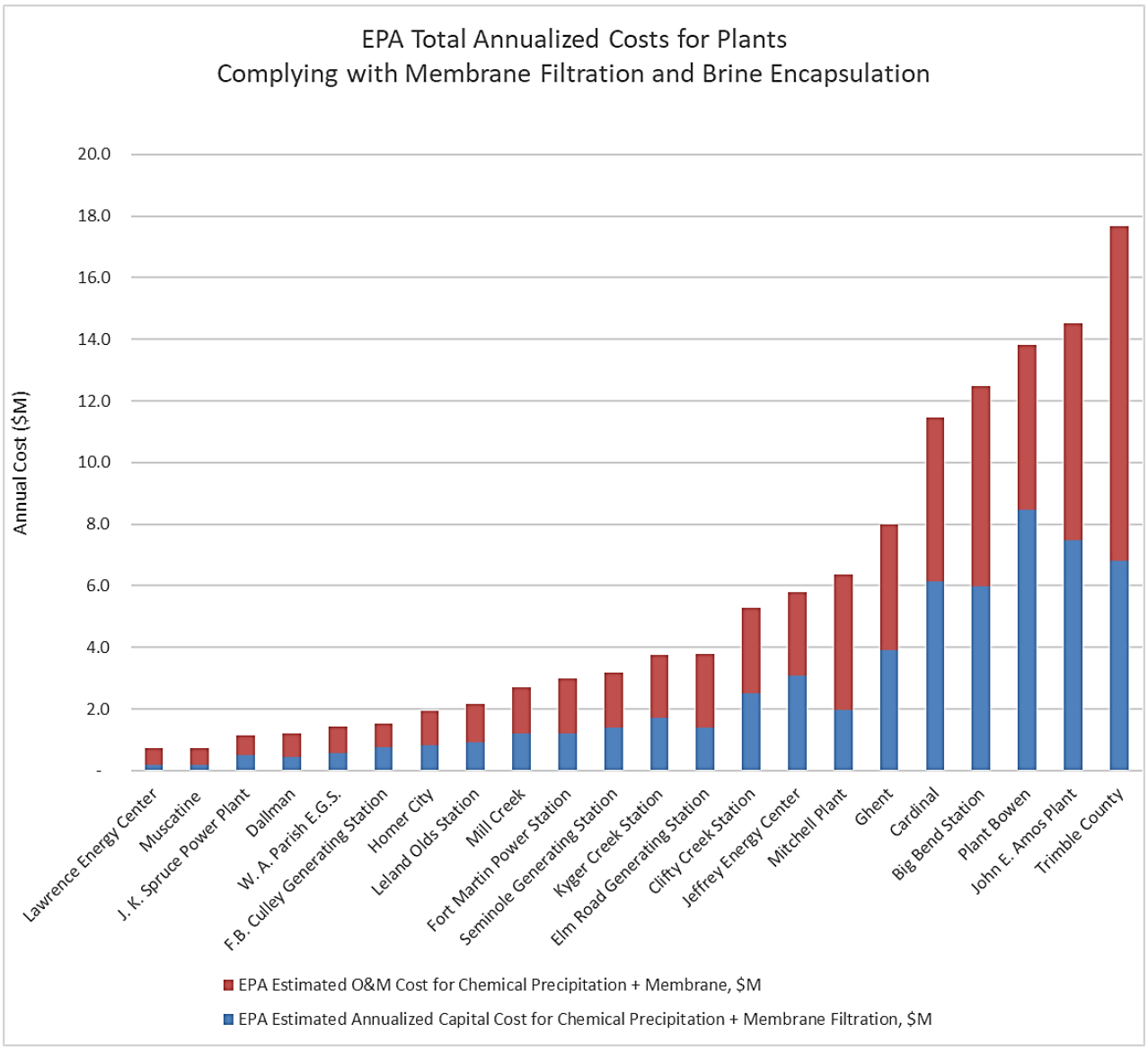


Figure 2-2. EPA estimate of total annualized costs for 22 plants complying with BAT regulatory option 3: CP, membrane filtration, and brine encapsulation, 2021$

Figure 2-3 shows a comparison of EPRI and EPA's estimate of total annualized cost for each plant treating FGD wastewater after 2023.

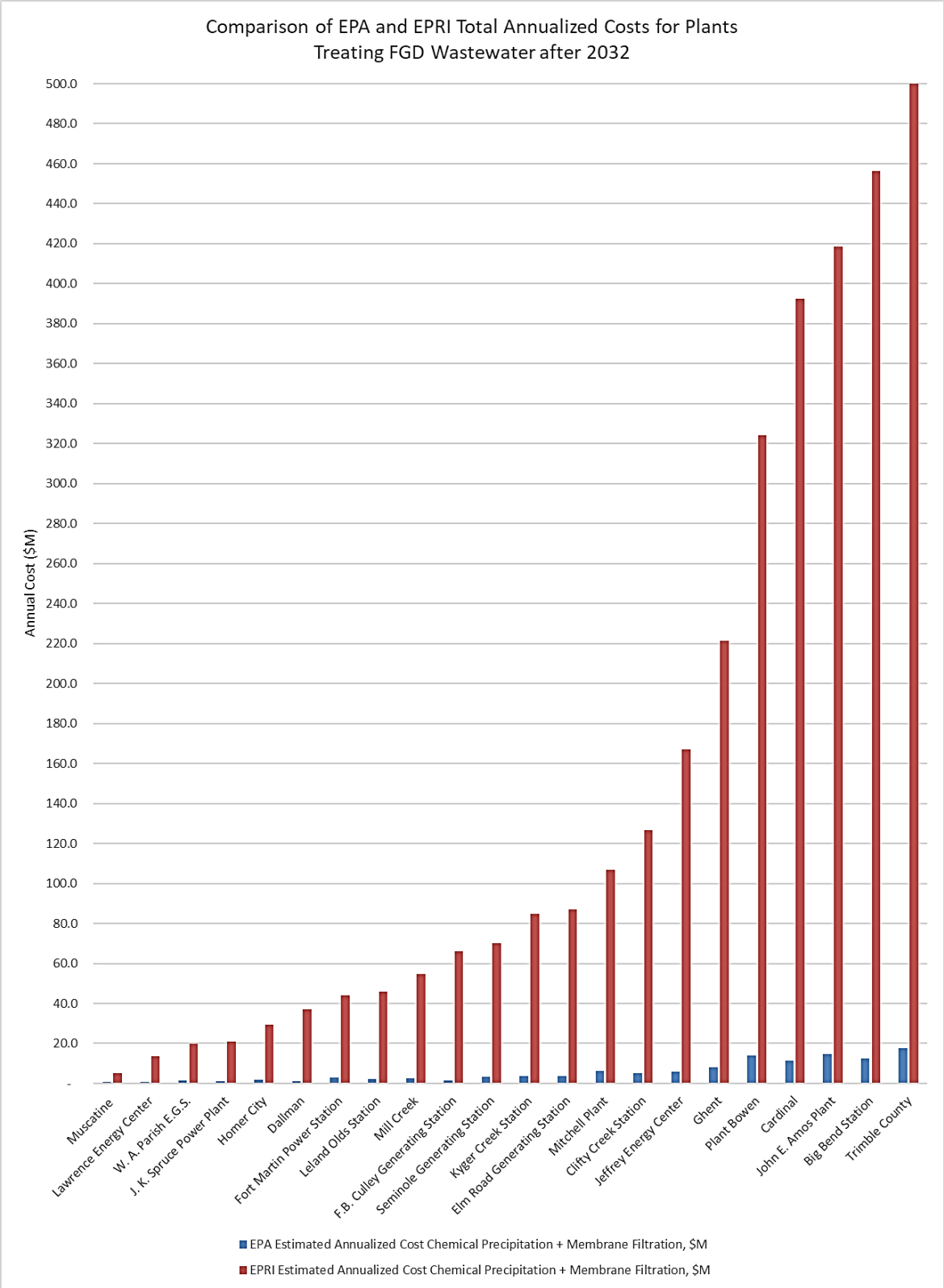


Figure 2-3. Comparison of EPA and EPRI estimate of total annualized costs for 22 plants complying with BAT regulatory option 3: CP, membrane filtration, and brine encapsulation, 2021$

EPA has significantly underestimated BAT costs for membrane filtration due to several key differences in flow rate, brine management, and encapsulation estimates.

As previously shown, EPRI's estimated costs for the industry to comply with membrane filtration is approximately 25 times higher than EPA's cost estimate for the same list of 22 plants. There are several key reasons for these differences, each of which is discussed below.

FGD peak flow with equipment redundancy should be used to estimate capital costs.

In the 2013 proposed ELG rule, EPA stated that the estimated flows for some FGD wastewater treatment systems were based on the typical or average flow reported by the power plant. That average flow rate was multiplied by a "mean capacity factor" of 1.99. EPRI agrees with the industry-standard approach of using a peaking factor as the basis for capital costs, as treatment systems must be able to treat to compliance levels at all operating flow conditions. However, in the 2019 cost estimate calculations, EPA did not multiply by a mean capacity factor, but instead asserted that plants can reduce to a lesser, optimized flow rate; therefore, designing for current average flow provides adequate conservatism [EPRI, 2020]. In this rulemaking, EPA has taken a similar approach as the 2019/2020 rulemaking, whereby treatment system equipment is sized based on FGD purge flow. In continuing to use average FGD purge flow to size and cost treatment equipment, EPA has not considered:

- The FGD peak flow that must be instantaneously processed by the membrane filtration system.
- The need to design the membrane filtration system for N+1 redundancy, which is typical in membrane applications. In this sizing approach, "N" is the peak design flow and the "+1" designates that a redundant equipment train is installed. Membrane systems are frequently taken offline for cleanings; therefore, it is critical to design membrane systems for a capacity greater than the peak design flow.
- In sizing the membrane filtration system, the capacity of existing CP pre-treatment systems installed must be considered. To maintain treatment system throughput, the membrane filtration system design flow should match the design capacity of the existing CP treatment system.

For the total industrywide flow of FGD wastewater needing treatment, EPRI estimates a peak/design flow of 17.3 million gallons per day (mgd) while EPA used 13.4 mgd (Table 2-3). This difference in flow rates contributes to the cost differences between EPA and EPRI.

Table 2-3. Comparison of EPA and EPRI flow basis used for capital and O&M cost basis

EPA ICR ID	Plant Name	Capital Cost Basis		O&M Cost Basis	
		EPA FGD Purge Flow (gpd)[1]	EPRI Peak FGD Flow (gpd)	EPA Optimized Flow (gpd)[1]	EPRI Annual Average FGD Purge Flow (gpd)
493	J. K. Spruce Power Plant	86,400	129,600	17,626	75,777
771	OVEC – Kyger Creek Station	385,920	385,920	241,200	335,583
904	Muscatine Power and Water Generating Station	7,500	28,800	4,688	7,200
1236	Mitchell Plant	486,000	796,320	308,813	397,894
1381	EME Homer City Generation L.P.	158,400	228,960	99,000	137,280
1674	Trimble County	1,644,985	2,468,160	1,644,985	1,664,480
2244	Georgia Power Company – Plant Bowen	2,052,000	2,160,000	769,500	1,080,000
2601	Ghent	928,800	1,393,920	565,020	842,851
3265	Cardinal	1,476,000	2,214,720	768,750	1,369,913
3309	Lawrence Energy Center	7,000	54,331	1,081	47,000
3464	W. A. Parish E.G.S.	95,040	142,560	59,400	78,585
3604	Mill Creek	252,972	380,160	158,108	229,231
5318	Clifty Creek Station	576,000	576,000	360,000	456,155
6334	Leland Olds Station	184,894	277,920	115,559	170,092
6377	Tampa Electric – Big Bend Station	1,435,680	1,684,272	957,125	1,495,043
7785	Seminole Generating Station	303,120	432,000	202,982	275,192
8353	Jeffrey Energy Center	720,000	720,000	348,300	587,520
8965	F.B. Culley Generating Station	157,622	236,160	19,703	216,000
9161	John E. Amos Plant	1,810,080	1,810,080	1,037,025	1,490,654
9225	Fort Martin Power Station	256,320	475,200	200,250	152,640
9971	Dallman	66,240	214,180	41,400	104,948
56068	Elm Road Generating Station	300,000	450,720	300,000	291,083
	Total	13,390,973	17,259,982	8,220,515	11,505,120

1. EPA reported flows used for compliance costs and pollutant loadings as shown in *Flue Gas Desulfurization Flow Methodology for Compliance Costs and Pollutant Loadings* [EPA, 2022a] and its reference *Flue Gas Desulfurization Flow Methodology and Compliance Costs and Pollutant Loadings* [EPA, 2020a]. Note: Some of the FGD purge plant flows reported in these references do not match the flows assumed by EPA in its fly ash availability review [EPA, 2023a], as shown in Table 1-2.

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FGD purge flow should be used instead of optimized flow to estimate membrane filtration O&M costs.

In evaluating the quantity of fly ash required for brine encapsulation [EPA, 2023d], EPA used the FGD purge flow as the basis for analyzing FGD flows and O&M requirements. EPRI agrees that the annual average FGD purge flow should be used in estimating fly ash requirements and associated O&M quantities.

In estimating O&M costs, however, EPA states that the optimized flow was used as the basis for developing O&M costs such as brine management. Therefore, in switching to using optimized flow, EPA's approach leads to a much lower brine management cost estimate.

Further, EPA states that "For each plant, EPA estimated two FGD purge flow rates: the FGD purge flow rate (the typical amount of wastewater from the FGD scrubber that is sent to FGD wastewater treatment) and the FGD optimized flow rate (a reduced rate that considers a reduction in FGD wastewater purged from the system, where equipment metallurgy could accommodate increased chloride concentration in the FGD system)." [EPA, 2023c]

Use of optimized flow assumes there is a reduction in FGD wastewater purged from the system whereby equipment metallurgy could accommodate the increased chloride concentration in the FGD system. Using this approach for a membrane system is not appropriate for the following reasons:

- As discussed in Section 1 and shown in Figure 1-8, membrane system performance and permeate recovery will notably decline as FGD wastewater concentrations, such as chloride and overall total dissolved solids (TDS), increase.
- Therefore, an "optimized" FGD purge flow, as EPA has proposed, would likely lead to higher TDS in FGD wastewater feed to the membrane system.
- The higher TDS concentration in the FGD feed leads to a greater tendency for membrane scaling and lower membrane system percent recovery.
- This reduction in permeate recovery can consequently lead to an increase in brine flow and higher fly ash demands and operating costs.
- Further, an increase in chloride and TDS concentrations to the membrane system may also lead to higher-grade metallurgy selection in the membrane system, thereby increasing costs.

As shown in Table 2-3, EPA used 8.2 mgd total industrywide flow of FGD wastewater in developing O&M costs for membrane filtration. This is approximately 5 mgd less than the reported typical FGD purge flow to the industry.

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Membrane system recovery that can be consistently achieved should be used; EPA has stated that 70% was "the average FGD wastewater recovery from the membrane treatment vendors." *However, it appears EPA uses a much higher recovery in its cost estimates.* recovery in its cost estimates.

As shown previously in Table 1-4, the membrane system recovery will significantly impact the volume of brine generated, the fly ash required, and the disposal costs to the landfill. In estimating potential costs to the industry, it is critically important to select an assumed membrane recovery that can be consistently achieved across the industry based on EPA's definition of typical CP treatment system effluent [Table 6-1, EPA, 2020b]. In considering this, EPRI employed 70 percent membrane recovery in its cost estimates. The selection of membrane recovery will have a significant impact on calculating all O&M quantities and costs.

To further illustrate the importance of selecting an appropriate recovery, EPRI has prepared several case studies and flow diagrams that compare a 70, 80, and 90 percent membrane recovery system. As shown in Figure 2-4 and Figure 2-6, the difference in brine management costs associated with 70 percent and 90 percent membrane recovery leads to a difference of $33 million in brine management costs, and difference in beneficial use of fly ash equal to $0.3 million, for the example case study of 153 gpm annual average FGD purge flow. A summary of the three case studies is shown in Table 2-4.

Table 2-4. Brine flow produced for 300 gpm peak / 153 gpm annual average FGD purge flow

Overall Membrane Recovery (%)	FGD Purge Flow (gpm)	Brine produced (gpm)	Fly ash required (tons/yr)	Total Fly Ash Produced – Disposed and Sold (tons/yr)	Supplemental Fly Ash Required (tons/yr)	Quicklime Required (tons/yr)	Net Increase in Residuals Disposed (dry tons/yr)
70	153	46	456,172	198,000	258,172	29,622	406,593
80	153	31	312,721	198,000	114,721	20,307	253,828
90	153	15	169,271	198,000	0	10,992	101,063

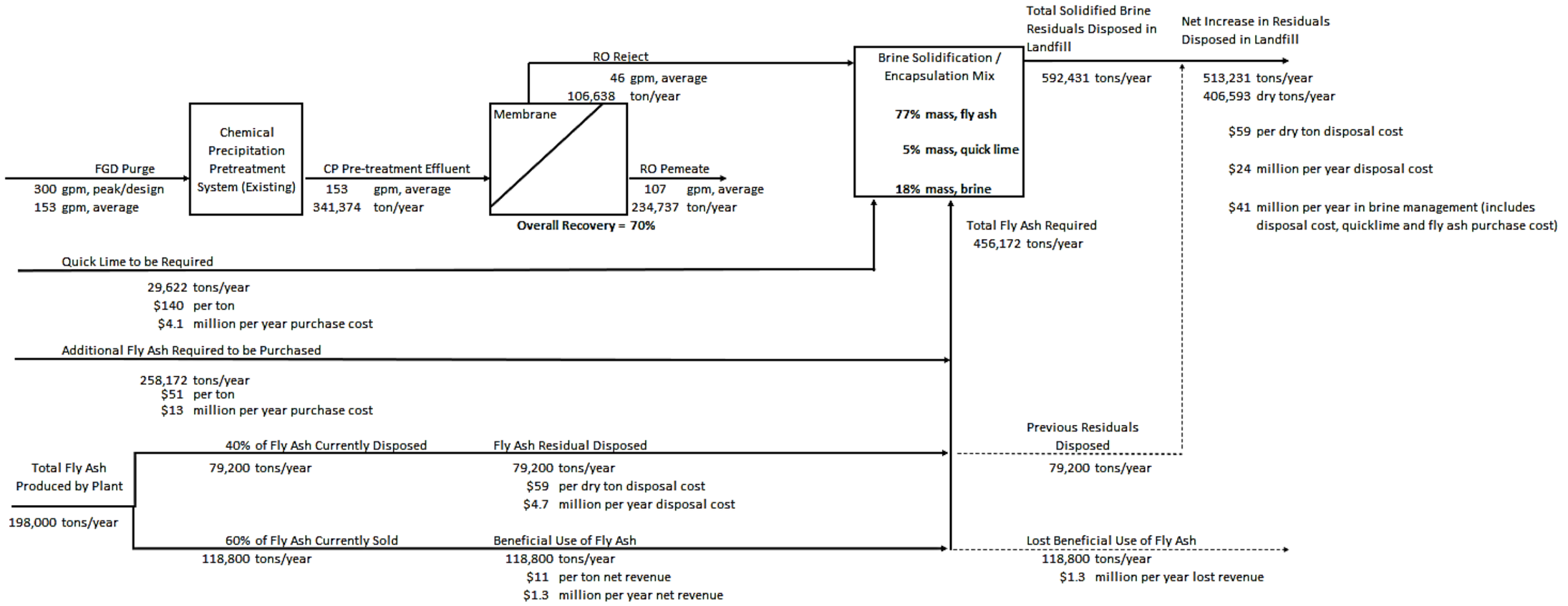


Figure 2-4. 70% recovery case study, 300 gpm peak / 153 gpm annual average FGD purge flow

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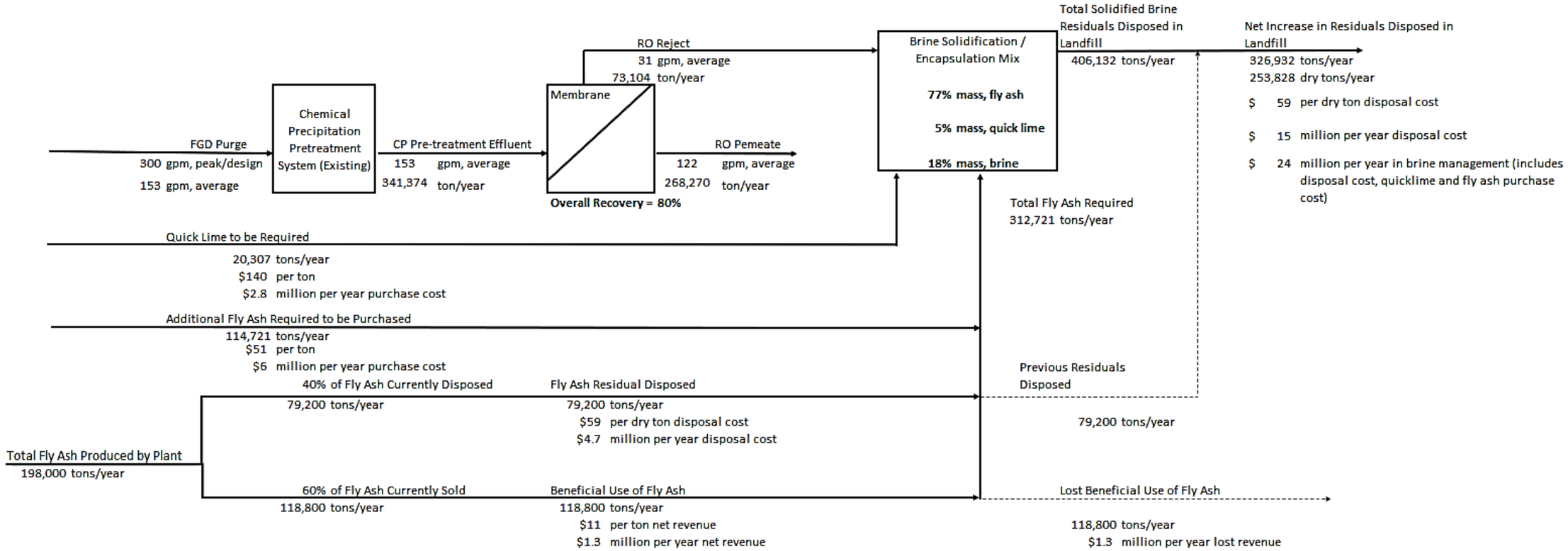


Figure 2-5. 80% recovery case study, 300 gpm peak / 153 gpm annual average FGD purge flow

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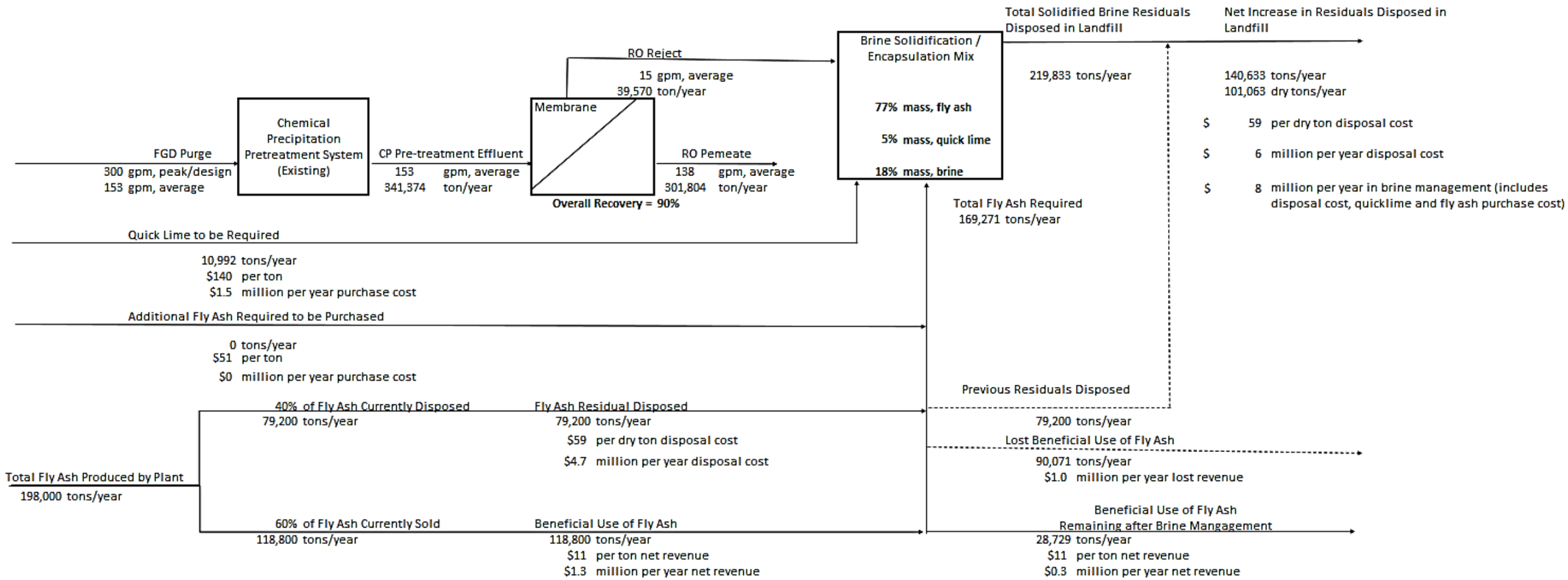


Figure 2-6. 90% recovery case study, 300 gpm peak / 153 gpm annual average FGD purge flow

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EPA has significantly underestimated the O&M costs associated with brine management and encapsulation using its current calculation methods. EPRI's site-specific O&M cost estimate for a single plant is 35 times higher than EPA's cost estimate.

EPRI is presenting estimated costs through a site-specific case study to further illustrate a comparison of EPRI and EPA's costs differences. EPRI is committed to advancing safe, reliable, affordable, and environmentally responsible electricity generation. EPRI's analysis indicates that the proposed regulatory option for FGD wastewater is not affordable for power generating utilities with potential impacts to the public.

To illustrate this specific case study cost comparison, EPRI has selected Kyger Creek Power Plant (EPA ICR Plant ID 771). The rationale for selecting this plant over other plants in the industry profile includes, and is summarized in Table 2-5:

- Kyger Creek has an FGD purge flow that is near the industry average
- Kyger Creek produces a total fly ash quantity that is near the industry average
- EPA-estimated fly ash produced is similar to the U.S. Energy Information Administration (EIA) estimate of fly ash produced

Table 2-5 presents FGD wastewater flowrates and fly ash production rates used by EPRI and EPA.

Table 2-5. Kyger Creek Comparison to Industry Averages

Plant Statistics	EPRI Value	EPA Value	Industry Average (Based on EIA Data)[1]
Capital Cost Flow Basis (gpm)	268	268	--
O&M Cost Flow Basis (gpm)	233	168	--
Fly ash produced (tons/year)	186,300	187,716	208,000

1. Average of total fly ash produced by plant over 3 years (2018 – 2020) based on EIA Form 923 Schedule 8A

EPRI reviewed EPA's cost estimate for this plant and the flow and fly ash data available on the docket [EPA, 2023a; EPA, 2023b; EPA, 2023d]. The information suggests that EPA's method of estimating site-specific O&M cost is significantly low.

EPRI used the flows and fly ash quantities shown in Table 2-5 to estimate brine management costs for comparison to EPA's O&M cost estimate.

As the basis for evaluating EPA's costs, EPRI used EPA's estimate of total fly ash produced for Kyger Creek in 2018, 2019, and 2020 of 203,354, 195,763, and 164,031 tons/year, respectively. EPRI calculated the average of these 3 years and used this as the basis for developing estimated costs, which was 187,716 tons per year. For Kyger Creek, EPA's assumed flow basis for

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estimating capital costs is 268 gallons per minute (gpm), and the optimized flow basis used to calculate O&M costs is 168 gpm.

In EPRI's cost estimates, the average of 2018, 2019, and 2020 fly ash production data for Kyger Creek, as reported by EIA Form 923 Schedule 8A, was used and calculated to be 186,300 tons per year. EPRI assumed the same flow basis for estimating capital costs for Kyger Creek (268 gpm), but used a higher flow basis to calculate O&M costs (233 gpm) compared to that assumed by EPA.

First, EPRI developed a case study and flow diagram based on EPA's flows, fly ash quantities and brine encapsulation ratio used as part of this rulemaking (Figure 2-7). Next, EPRI evaluated both EPA and EPRI's flows and fly ash quantities and costs based on a membrane system recovery of 70 percent. The block flow diagrams depicting the brine management scenarios using EPA and EPRI assumed quantities are shown in Figure 2-8 and Figure 2-9, respectively.

As shown in Figure 2-8, EPRI used EPA's flow basis and an assumed 70 percent membrane recovery to estimate the annual average reject flow as 50 gpm and the permeate flow as 118 gpm. Based on the mass flow rate of the RO reject, 117,092 tons per year, and the assumed encapsulation mixture of 77 mass percent fly ash/18 mass percent brine/5 mass percent quick lime, the total mass of quick lime required is 32,526 tons per year. This equates to a $4.6 million per year purchase cost based on the $140 per ton unit cost of quick lime.

Kyger Creek is estimated to produce 187,716 tons per year of fly ash based on EPA's rule-of-thumb estimate, all of which currently is being disposed. Kyger Creek does not sell any fly ash. Therefore, it is estimated that Kyger Creek would have 187,716 tons per year available for brine encapsulation; however, the mass balance shows that Kyger Creek would require a total of 500,894 tons per year of fly ash, meaning Kyger Creek would need to acquire (purchase) an additional 313,178 tons per year of fly ash. The total solidified brine residual to be hauled and disposed in landfill is 650,512 tons per year. Subtracting out the fly ash already being disposed (187,716 tons per year), a net total of 462,796 tons per year or 345,704 dry tons per year (deducting the mass of the brine) would be deposited in the landfill.

EPRI is assuming a unit disposal cost of $59 per dry ton, which is escalated to 2021 dollars based on EPA's unit disposal costs presented in the 2013 rulemaking. This increase in residual waste disposal quantity equates to an additional $20 million per year in disposal costs. The total brine management costs, including purchased quick lime, purchased additional fly ash, and net increase in residual waste disposed in the landfill, equals approximately $41 million per year.

The same methods were used in developing Figure 2-9, except that EPRI assumed flows and fly ash quantities were used. Since the EPRI and EPA's basis for design flow and fly ash production for Kyger Creek are nearly the same (Table 2-5), the only notable difference in Figure 2-7 is the annual average FGD flow assumed, i.e., EPA assumed 168 gpm optimized FGD flow and EPRI assumed 233 gpm annual average FGD purge flow. Therefore, the difference in EPA and EPRI assumed membrane feed flow is 65 gpm. As seen in Figure 2-7, this difference in feed flow leads to a 20-gpm increase in assumed brine flow and a significant difference in brine

management cost calculations. The estimated brine management costs using EPRI's assumed average FGD flow rate leads to a nearly 60 percent increase in brine management costs.

EPA's assumptions and methods for calculating brine management costs are unknown by EPRI; however, EPA has stated that the total O&M cost for membrane filtration at Kyger Creek is estimated to be $2 million per year. Given these calculation results and assumptions previously provided, EPA's costs appear to be 20 times too low (Table 2-6).

Further, EPRI's analysis of EIA revenue data shows that the average revenue for Kyger Creek in years 2018 through 2020 was approximately $314,500,000. EPRI's estimated O&M cost for Kyger Creek is $70,000,000 per year. This analysis indicates that the annual O&M cost for Kyger Creek alone, before accounting for capital costs, would be approximately 22 percent of Kyger Creek's total annual revenue.

Table 2-6. Kyger Creek Cost Comparison, Costs 2021$

Cost Item	Units	EPA Reported O&M Methods and Cost	EPRI Costing Method EPA Flow Basis	EPRI Costing Method EPRI Flow Basis
Quick Lime Purchase	Tons/year	?	32,526	45,110
	$M/year	?	$ 4.6	$ 6.3
Additional Fly Ash Purchase	Tons/year	?	313,178	508,393
	$M/year	0	$ 16	$ 26
Net Increase in Residuals to Landfill	Dry Tons/year	?	345,704	553,503
	$M/year	0	$ 20	$ 33
Subtotal Brine Management	$M/year	**?**	**$41**	**$ 65**
Total Annual O&M Cost	$M/year	**$ 2.0**	**--**	**$ 70**

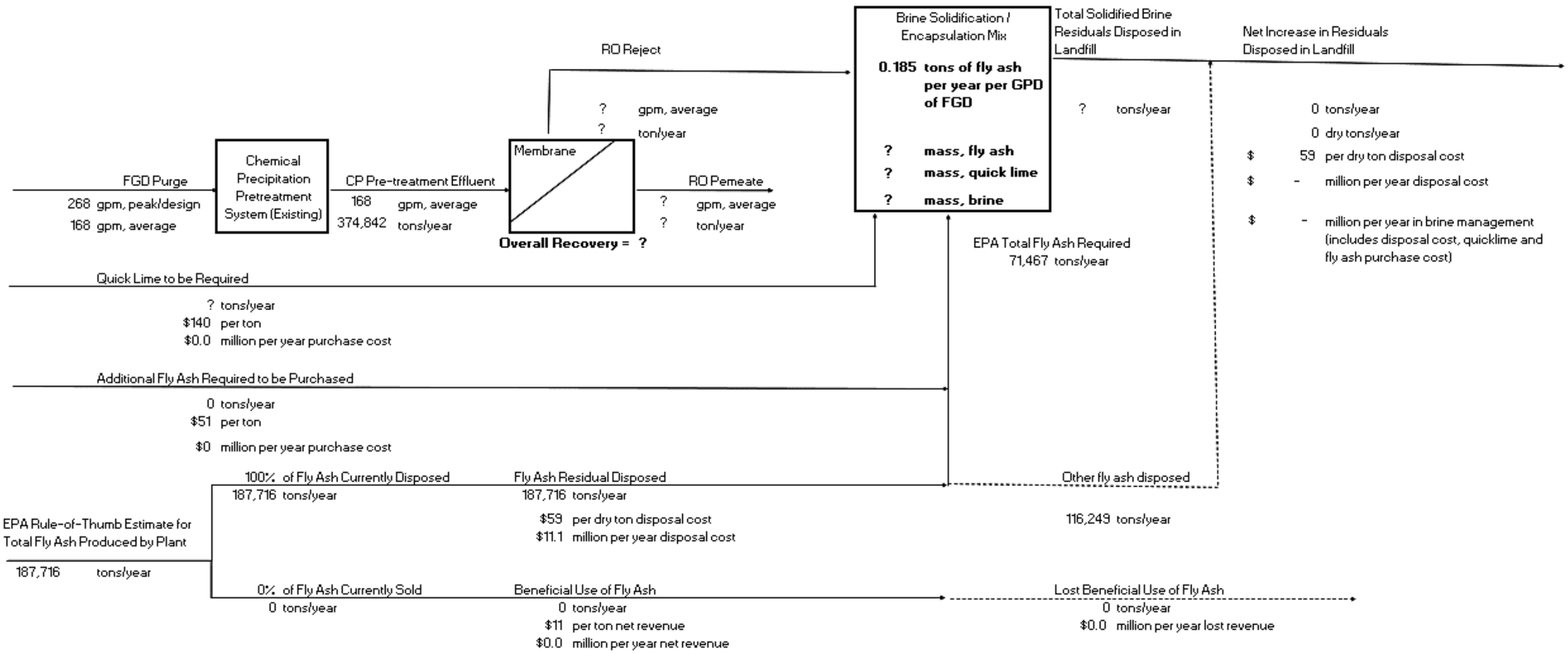


Figure 2-7. EPA brine management approach and costs – Kyger Creek

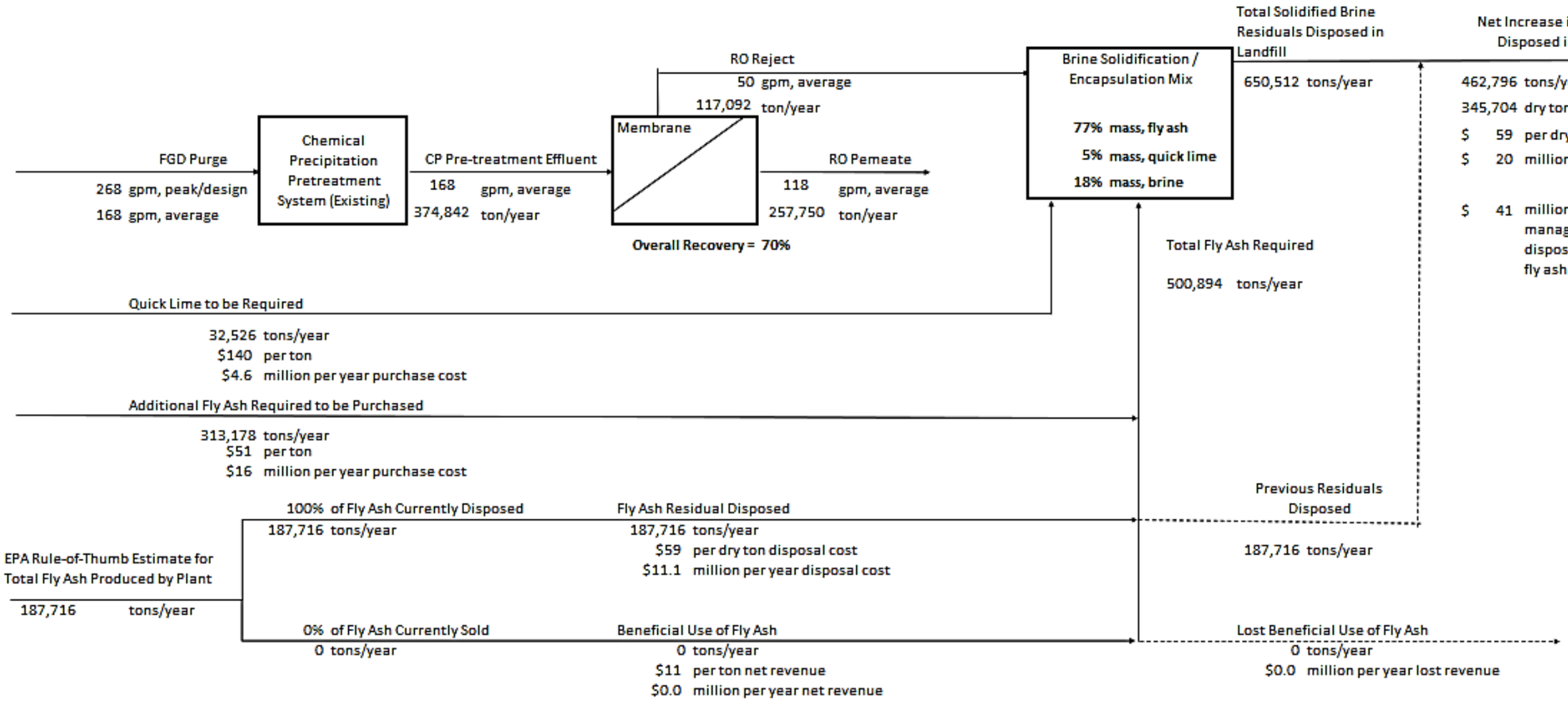


Figure 2-8. EPRI brine management approach using EPA flow and fly ash quantities – Kyger Creek

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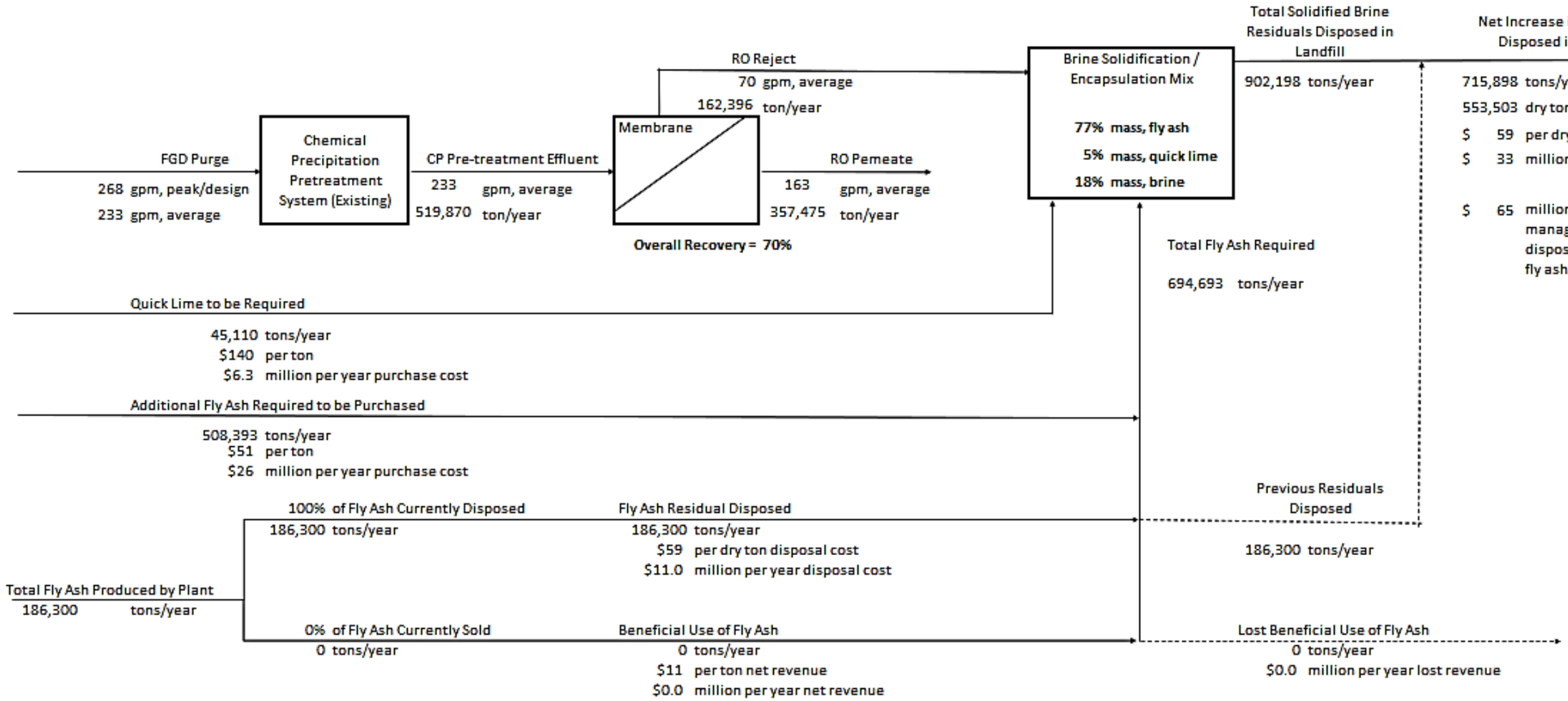


Figure 2-9. EPRI brine management approach, flow and fly ash quantities, and costs – Kyger Creek

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Fly ash shortages will lead sites to experience challenges and significant costs to acquire or harvest additional fly ash, including excavation, transport, and drying the harvested ash.

Fly ash shortages would require deficit plants to consider alternative brine management strategies. This could lead plants to develop alternative material sources such as landfilled fly ash, offsite produced fly ash, or offsite produced lime. Alternative material sources are likely to have higher associated costs than onsite production fly ash.

EPA states that "If a deficit of fly ash remains at any plants, EPA expects that it will be minimal, and may be addressed by using fly ash generated in previous years for encapsulation by accessing fly ash from storage areas or landfills..." [EPA, 2023d]. There are important technological considerations and significant cost implications associated with using ash from landfills.

First, landfills do not allow for fly ash storage in dry, as-produced conditions. Instead, landfill placement requires the addition of moisture to allow compaction and to control fugitive emissions. Therefore, ash placed in a landfill will be wet and not suitable for use in encapsulation.

Industry specifications for beneficial use in concrete, like ASTM C 618, require fly ash moisture contents of less than 3 percent. Commercial waste stabilization operations use dry, as-produced fly ash. EPRI's research on brine encapsulation used dry, as-produced fly ash. Therefore, landfilled fly ash is unlikely to be directly useful in brine management.

It is unclear from EPA's assessment of fly ash availability [EPA, 2023d] if EPA envisions landfilled fly ash being used directly for encapsulation or it being processed prior to use in encapsulation. If EPA envisions that shortages in onsite-produced fly ash will be mitigated with ash removed directly from landfills, then the encapsulation approach needs to account for the water already contained in the landfilled fly ash. For the majority of sites, there will be an additional cost to excavate, process, and dry the fly ash before it can be used as an encapsulation additive and mixed with brine.

EPRI has estimated that the cost to harvest fly ash from storage areas or landfills is approximately $63 to $128 per ton of fly ash harvested. This estimate is comprised of $40 to $105 per ton for civil components to harvest the fly ash and $23 per ton for drying the harvested fly ash to less than 3 percent moisture prior to encapsulation with the membrane brine. The civil cost was estimated from the average contractor's civil cost for harvesting fly ash as presented in the Coal Combustion Residuals Recycling/Beneficial Use Assessment Business Plan prepared for Dominion Energy Virginia [AECOM, 2019]. The civil components include dewatering with water treatment, excavation, air drying to between 25 and 35 percent moisture content, screening, transportation, loading, and/or any other handling requirements to get the ash to the recycling/beneficiation process. The cost per ton for drying the harvested fly ash was based on information provided by two fly ash drying system equipment

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manufacturers. The fly ash drying system manufacturers proposed scope of supply included a complete plant with feed bins, collector conveyor, weigh conveyor, parallel flow rotary dryer, combustion chamber, cyclone, baghouse, and control system. The dryer systems were assumed to be installed in a 3x50% configuration to provide n+1 redundancy.

EPA appears to have misreported the costs for six plants that plan to operate past 2032 and would be required to install membrane filtration and encapsulation systems.

EPA appears to have misreported the membrane filtration and encapsulation (ZLD) system costs stated in *Generating Unit-Level Costs and Loadings Estimates by Regulatory Option for the 2023 Proposed Rule* [EPA, 2023a] for six plants that plan to operate past 2023:

- Georgia Power Company's Plant Bowen
- PPL Corporation's Ghent plant
- Buckeye Power, Inc.'s Cardinal plant
- Westar Energy's Lawrence Energy Center
- NRG Electric's W.A. Parish Electricity Generating Station
- PPL Corporation's Mill Creek plant

EPA's cost basis for proposed regulatory option 3 assumes that all plants have already installed CP+LRTR equipment required to comply with the 2020 BAT determination for FGD wastewater, and that any plants that opted into VIP would have already installed evaporation technology and there would be zero costs to install the ZLD system. In *Table 4. Unit-Level costs for FGD Wastewater Treatment under Regulatory Option 3* [EPA, 2023a], the capital, O&M, and one-time annual costs for the previously mentioned six plants are presented as zero dollars. This suggests these facilities either opted into VIP or are subcategorized as CP+LRTR based on *Table 8. Technology Rule Basis* [EPA, 2023a]. EPRI believes this is incorrect. Based on EPRI's review of the database [EPA, 2023b], these six plants do not plan to retire or change combustion fuel by 2023, nor did they opt into VIP and install evaporative technology. As such, these plants would incur capital costs for procuring and installing a ZLD system and associated O&M costs. A presentation of these ZLD system capital cost discrepancies are shown in Table 2-7. EPRI believes that costs should be applied for these six plants for a ZLD system and requests EPA to review and correct its documentation to include these costs.

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Table 2-7. EPA-reported Capital Cost Discrepancy for Several Plants

Plant Name	SE Unit	EPA ICR ID	Capital Cost Presented in EPA Database SE10416	Capital Cost Presented in Table 4 [EPA, 2023a]
Georgia Power Company – Plant Bowen	3	2244	$20,932,888	$0
Georgia Power Company – Plant Bowen	4	2244	$20,181,932	$0
Ghent	1	2601	$10,996,814	$0
Ghent	2	2601	$12,290,557	$0
Ghent	3	2601	$7,115,585	$0
Ghent	4	2601	$11,320,249	$0
Cardinal	2	3265	$13,368,867	$0
Cardinal	3	3265	$40,106,602	$0
Lawrence Energy Center	3	3309	$2,085,805	$0
W. A. Parish E.G.S	8	3464	$5,871,525	$0
Mill Creek	3	3604	$3,342,946	$0
Mill Creek	4	3604	$4,128,014	$0

EPA has not accounted for the higher costs for plants that will retire or repower in less than 20 years.

EPRI analyzed data for the anticipated year that plants will permanently cease coal combustion either due to plant retirement or due to the plant repowering to a non-coal fuel source, such as natural gas or green hydrogen. EPRI evaluated the cost for the 22 plants that would be required to install a membrane filtration system based on proposed regulatory option 3. Table 2-8 presents total annualized costs using two approaches: (1) capital cost annualized over 20-year design life and (2) capital cost annualized based on how long each plant is anticipated to generate FGD wastewater past the “no later than” compliance deadline of December 31, 2029 as stated in the proposed rulemaking [US, 2023].

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Table 2-8. EPRI cost estimates for plants to comply with CP, membrane filtration, and brine encapsulation considering number of years operating before retirement, 2021$

EPA ICR ID	Plant Name	Estimated Year of Plant Retirement or Repowering[2]	Years Operating After 2029	EPRI Cost Estimate[1]			
				Capital Cost ($M)	O&M Cost ($M/yr)	Total Annualized Cost – 20 Years ($M)[3]	Total Annualized Cost – Years Operating ($M)[4]
493	J. K. Spruce Power Plant	2052	20	51	16	21	21
771	OVEC – Kyger Creek Station	2040	11	159	70	85	91
904	Muscatine Power and Water Generating Station	2052	20	24	3	5	5
1236	Mitchell Plant	2040	11	223	86	107	116
1381	EME Homer City Generation L.P.	2052	20	67	23	29	29
1674	Trimble County	2066	20	726	432	500	500
2244	Georgia Power Company – Plant Bowen	2035	6	522	275	324	385
2601	Ghent	2037	8	376	186	221	249
3265	Cardinal	2052	20	610	335	392	393
3309	Lawrence Energy Center	2052	20	38	10	14	14
3464	W. A. Parish E.G.S.	2045	16	49	15	20	20
3604	Mill Creek	2052	20	112	44	55	55
5318	Clifty Creek Station	2040	11	221	106	127	135
6334	Leland Olds Station	2052	20	106	36	46	46
6377	Tampa Electric – Big Bend Station	2052	20	641	396	456	456
7785	Seminole Generating Station	2052	20	139	57	70	70
8353	Jeffrey Energy Center	2039	10	268	142	167	180
8965	F.B. Culley Generating Station	2052	20	117	55	66	66

EPA ICR ID	Plant Name	Estimated Year of Plant Retirement or Repowering[2]	Years Operating After 2029	EPRI Cost Estimate[1]			
				Capital Cost ($M)	O&M Cost ($M/yr)	Total Annualized Cost – 20 Years ($M)[3]	Total Annualized Cost – Years Operating ($M)[4]
9161	John E. Amos Plant	2040	11	601	362	418	442
9225	Fort Martin Power Station	2052	20	119	33	44	44
9971	Dallman	2045	16	86	29	37	38
56068	Elm Road Generating Station	2035	6	158	72	87	105
Total Annualized Cost to Industry						3,292	3,461

ICR = Information Collection Request

$M/yr = million dollars per year (2021 dollars)

1. Includes 22 plants that are assumed to operate past 2032 and therefore required to comply with regulatory option 3 BAT: CP, membrane filtration, with brine encapsulation
2. Current "announced" year when facility will permanently cease coal combustion, either due to plant retirement or due to repowering to a non-coal fuel source, such as natural gas or green hydrogen
3. Total annualized cost which is a sum of the annualized cost of capital (assumes 7% interest rate and 20-year life) and the annual O&M cost
4. Total annualized cost which is a sum of the annualized cost of capital and the annual O&M cost. Annualized cost of capital is calculated based on a 7% interest rate and the number of operating years. The number of operating years are calculated from an assumed in-service date corresponding to the "no later than" proposed regulatory compliance date of December 31, 2029 to the plant's estimated retirement or repowering date.
5. EPRI's analyses was solely focused on the proposed ELG Rule and did not consider the impact of other proposed and future environmental regulations, including the proposed Greenhouse Gas 111(d) Rule. These various environmental regulations may impact the currently announced retirement dates.

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Many sites will incur costs that are inconsistent with EPA's estimated costs for CP, membrane filtration, and encapsulation. Fly ash availability and FGD purge flow and quality will ultimately drive plant decisions related to technologies required to achieve ZLD and associated costs. EPRI's estimate of the lowest cost option for ZLD is 6 times higher than EPA's cost estimate for the same list of plants.

EPRI estimated the cost for the 22 industry plants that would be required to comply with regulatory option 3 to convert to a ZLD thermal and/or membrane-based treatment system. EPRI considered potential technology choices and estimated cost to the industry to convert to one of three potential thermal and/or membrane treatment systems:

1. Chemical softening, vapor-compression evaporation, and crystallization (CS + VCE/CRX), as presented in Appendix C.
2. Chemical precipitation, vapor-compression evaporation, and brine solidification (CP+VCE/BS), as presented in Appendix D
3. Chemical precipitation, advanced membrane filtration and brine solidification (CP+AMF/BS), as presented in Appendix E.

This analysis considered the FGD wastewater flows and fly ash quantities produced by each plant to arrive at one of the three technology options that appeared most suitable for each site and yielded the lowest total estimated annualized cost over a 20-year period. Table 2-8 provides a summary of the results, and Appendix F provides further analysis details.

EPRI's analysis indicated:

- Only three plants produced sufficient fly ash for membrane filtration.
- Membrane filtration was not the lowest cost technology alternative for any of the 22 plants.
- For 10 plants, thermal evaporation with brine solidification (CP + VCE/BS) was the lowest cost technology alternative.
- For the remaining 12 plants, installing a thermal evaporator and crystallizer (CS + VCE/CRX) was estimated to be the lowest cost technology alternative.

In actual applications, plants would need to conduct a detailed analysis of their site-specific flows and FGD wastewater quality to arrive at a technology selection; however, this analysis shows that membrane filtration alone is unlikely to be widely applicable across the industry.

As shown in Table 2-9, EPRI's estimate of lowest cost alternatives for ZLD are still 6 times higher than EPA's estimate for membrane filtration.

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Table 2-9. Lowest Cost ZLD Analysis for 22 Plants under Regulatory Option 3

EPA ICR ID	Plant Name	EPRI Cost Estimate[1]				EPA Cost Estimate[2]			
		Technology Basis	Capital Cost ($M)	O&M Cost ($M/yr)	Total Annualized Cost ($M)[3]	Technology Basis	Capital Cost ($M)	O&M Cost ($M/yr)	Total Annualized Cost ($M)[3]
493	J. K. Spruce Power Plant	CP+VCE/BS	35	7	10	Membrane Filtration	6	0.6	1.1
771	Kyger Creek Station	CP+VCE/BS	66	14	20	Membrane Filtration	18	2.0	3.8
904	Muscatine	CP+VCE/BS	16	2	3	Membrane Filtration	2	0.5	0.7
1236	Mitchell Plant	CP+VCE/BS	104	20	30	Membrane Filtration	21	4.4	6.4
1381	Homer City	CS+VCE/CRX	97	5	14	Membrane Filtration	9	1.1	1.9
1674	Trimble County	CS+VCE/CRX	438	39	80	Membrane Filtration	73	10.8	17.7
2244	Plant Bowen	CS+VCE/CRX	402	27	65	Membrane Filtration	90	5.3	13.8
2601	Ghent	CS+VCE/CRX	298	21	49	Membrane Filtration	42	4.1	8.0
3265	Cardinal	CS+VCE/CRX	408	33	71	Membrane Filtration	65	5.3	11.5
3309	Lawrence Energy Center	CP+VCE/BS	22	4	6	Membrane Filtration	2	0.5	0.7
3464	W. A. Parish E.G.S.	CP+VCE/BS	37	6	9	Membrane Filtration	6	0.9	1.4
3604	Mill Creek	CP+VCE/BS	65	11	17	Membrane Filtration	13	1.5	2.7
5318	Clifty Creek Station	CS+VCE/CRX	171	12	28	Membrane Filtration	27	2.8	5.3
6334	Leland Olds Station	CP+VCE/BS	54	8	13	Membrane Filtration	10	1.2	2.2
6377	Big Bend Station	CS+VCE/CRX	343	33	65	Membrane Filtration	64	6.5	12.5
7785	Seminole Generating Station	CP+VCE/BS	71	14	21	Membrane Filtration	15	1.8	3.2
8353	Jeffrey Energy Center	CS+VCE/CRX	195	14	32	Membrane Filtration	33	2.7	5.8
8965	F.B. Culley Generating Station	CS+VCE/CRX	99	7	16	Membrane Filtration	8	0.8	1.5

EPA ICR ID	Plant Name	EPRI Cost Estimate[1]				EPA Cost Estimate[2]			
		Technology Basis	Capital Cost ($M)	O&M Cost ($M/yr)	Total Annualized Cost ($M)[3]	Technology Basis	Capital Cost ($M)	O&M Cost ($M/yr)	Total Annualized Cost ($M)[3]
9161	John E. Amos Plant	CS+VCE/CRX	359	37	71	Membrane Filtration	80	7.0	14.5
9225	Fort Martin Power Station	CP+VCE/BS	76	12	19	Membrane Filtration	13	1.8	3.0
9971	Dallman	CS+VCE/CRX	93	4	13	Membrane Filtration	5	0.8	1.2
56068	Elm Road Generating Station	CS+VCE/CRX	148	9	23	Membrane Filtration	15	2.4	3.8
TOTAL		--	3,596	339	677	--	613	65	122

$M/yr = million dollars per year (2021 dollars)

1. Includes 22 plants that are assumed to operate past 2032 and therefore required to comply with regulatory option 3 BAT: CP, membrane filtration, with brine encapsulation. EPRI estimated the lowest cost technology alternative for sites to achieve ZLD
2. EPA's cost estimate for 22 plants that would be required to comply with regulatory option 3 [EPA, 2023a and EPA, 2023b]
3. Total annualized cost which is a sum of the annualized cost of capital (assumes 7% interest rate and 20-year life) and the annual O&M cost

Leasing treatment equipment does not provide significant costs savings if needed for multiple years

The EPA's ELG documents include mention of leasing of treatment equipment. EPRI agrees that this may be more economical for short-term applications, such as emptying water from an impoundment or infrequent maintenance events. However, after a time, the cost of leasing becomes comparable to, or exceeds, purchasing the same equipment. The duration at which leasing exceeds cost of purchase varies by equipment and is typically two to five years. Many of power plants in the industry will need FGD treatment for longer. It should also be considered that equipment is typically 20 to 25 percent of total installed project cost. The balance of plant costs required when leasing treatment equipment include foundations, piping to and from treatment, bringing power and other utilities to treatment, a structure to protect equipment from weather, integration with plant control systems, and the engineering of the treatment system.

Technical challenges with leasing treatment equipment include:

- FGD water's corrosivity is likely not compatible with metallurgy of most equipment available for lease
- Most plants have FGD flow greater than leasable equipment's capacity

- Not all needed equipment can be leased, so some would need to be purchased
- Equipment available for lease may not be sufficient for the number of plants that need treatment

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EXHIBIT 13

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May 30, 2023

Via www.regulations.gov

Mr. Richard Benware
Engineering and Analysis Division
Office of Water, (4303T)
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1200 Pennsylvania Ave. N.W.
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Re: Comments on EPA's Proposed Rule; Supplemental Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category, 88 Fed. Reg. 18,824 (Mar. 29, 2023), EPA-HQ-OW-2009-0819

Dear Mr. Benware:

Attached are the Comments of the Utility Water Act Group (UWAG) on EPA's Proposed Rule for the Supplemental Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category, EPA-HQ-OW-2009-0819.

We appreciate the opportunity to comment. Please contact me at (202) 955-1629 if you have any questions.

Sincerely,

Brian R. Levey

Brian R. Levey

Attachment



Comments of the Utility Water Act Group on
Environmental Protection Agency Proposed Rule;
Supplemental Effluent Limitations Guidelines and Standards for the
Steam Electric Power Generating Point Source Category

88 Fed. Reg. 18,824 (Mar. 29, 2023)
Docket ID No. EPA–HQ–OW–2009–0819

May 30, 2023

www.utilitywateractgroup.org

Executive Summary

EPA's new proposed effluent limitations guidelines (ELG) rule represents a staggering change of course on wastewater treatment requirements that were just imposed in EPA's 2020 ELG rule. The electric power industry is transitioning to low- and zero-carbon power as fast as possible consistent with providing affordable and reliable energy. This rulemaking threatens to disrupt those efforts by diverting time and money to a mid-course change unlikely to yield benefits commensurate with its costs. The Utility Water Act Group (UWAG)[1] urges EPA to preserve key aspects of—and tremendous industry and public investments made in reliance upon—EPA's 2020 ELG rule.

A. EPA Should Preserve Key Aspects of the 2020 ELG Rule.

EPA's final 2020 ELG Rule required covered facilities to either commit millions of dollars and years of time to installing new wastewater treatment equipment, or retire. Numerous plants announced plans to retire, and the remainder are now incurring substantial costs to comply with the 2020 Rule's still-binding requirements. Naturally, the costs to comply with the 2020 Rule will be borne by the public in the form of higher electricity rates.

Now EPA is proposing another new ELG rule that would require facilities to abandon ongoing installation and startup of new equipment required by the 2020 Rule, and replace it with different, highly expensive and unproven technology EPA specifically rejected in the 2020 Rule. The result will be a loss of hundreds of millions of dollars on equipment the rule renders obsolete

[1] UWAG is a voluntary, non-profit, unincorporated group of 129 energy companies, which own and operate over fifty percent of the nation's total generating capacity, and three national trade associations of energy companies. The individual energy companies operate power plants and other facilities that generate, transmit, and distribute electricity to residential, commercial, industrial, and institutional customers. UWAG's purpose is to participate on behalf of its members in federal agency rulemakings under the Clean Water Act and related statutes, such as NEPA, and in related proceedings.

just as it is being installed and started up, compounded by substantial additional costs for new equipment required by the proposed rule, further increasing the total cost of electricity to the public and prompting more retirements of reliable baseload sources of electricity. The proposed rule's reversal in course is not supported by the facts and lacks a proper basis under the law.

EPA should preserve the key aspects of, and industry's investments to comply with, the 2020 Rule. Specifically, UWAG urges EPA to preserve its 2020 determinations as to membrane technology by either:

- continuing to recognize that membrane filtration is not nationally available or economically achievable, and poses unacceptable environmental risks; or
- allowing facilities that have made irreversible commitments of resources to comply with the 2020 Rule to continue under the limits established by that rule until 2032, at which point those facilities must either meet new proposed zero discharge requirements or retire or repower by 2035.

These recommendations will allow EPA to ensure that electric utilities and the public are not compelled to incur significant costs in reliance on the 2020 Rule, then suddenly deprived of the benefits of those expenditures and compelled to incur another layer of substantial costs that renders continued operation of reliable baseload facilities uneconomic. As the Supreme Court explained nearly thirty years ago:

> Elementary considerations of fairness dictate that individuals should have an opportunity to know what the law is and to conform their conduct accordingly; settled expectations should not be lightly disrupted. … In a free, dynamic society, creativity in both commercial and artistic endeavors is fostered by a rule of law that gives people confidence about the legal consequences of their actions."

Landgraf v. USI Film Prods., 511 U.S. 244, 265–66 (1994).

B. EPA Must Explain and Support Its Reversal In Course.

UWAG urges EPA not to proceed toward final ELG limits based on unsupported membrane technology that it rejected in 2020. If EPA nonetheless proceeds with a membrane-

based ELG rule, it must explain its reversal in course. In particular, EPA should specifically address substantial reliance interests by utilities and the public who irretrievably incurred hundreds of millions of dollars in costs due to the still-binding 2020 Rule.

EPA should further confirm that it has not, as suggested by various media reports, reversed course and proposed costly new ELG requirements on top of ongoing costs to comply with the 2020 Rule in furtherance of an "all in" goal to close coal plants. EPA also should explain and, as appropriate, adjust the retirement provisions of the Proposed Rule so that facilities that have made irretrievable investments in compliance with the 2020 Rule are not unduly excluded from the opportunity to either continue to operate under the 2020 Rule or retire.

C. Any New ELG Rule Must Be Reproposed and Make Important Changes.

EPA should make fundamental changes to the proposed rule and republish it for an adequate public comment period. The current record in support of the proposed rule does not demonstrate that membrane technology is nationally available or economically achievable, or that its environmental risks are acceptable. To the contrary, the few examples of uses of membrane technology referenced in the proposed rule lack detail, are technically flawed, and do not account for full-scale operations. And EPA's analysis of wastewater treatment technology for leachate excludes nearly half of the potentially regulated facilities. Equally problematic, the 60-day comment period was not only shorter than prior, less complex ELG proposals but was far less than necessary for regulated entities to analyze the 80-page, single-space proposal with over 1,300 attachments, and address EPA's request for comments on over 125 topics.

EPA should issue a new proposal that addresses and corrects these flaws and allow a sufficient time for public comment if it intends to proceed with this rulemaking. If EPA declines to do so, it should (at a minimum) make the following key adjustments:

- **Tailor the Rule to Preserve Investments Made in Reliance on EPA's 2020 ELG Rule.**
  - Modify the proposed Early Adopter subcategory to:
    - establish a qualification deadline based on meeting the 2020 Rule discharge limits by the applicability date in a facility's permit;
    - allow facilities that have installed biological treatment based on the 2020 Rule to either: (i) cease coal combustion at a later date than December 31, 2032 (no earlier than December 31, 2035) or (ii) continue to operate subject to zero liquid discharge (ZLD) limits by a permit writer's "as soon as possible" (ASAP) date between December 31, 2032, and December 31, 2040.
  - Establish a new subcategory, if EPA does not incorporate UWAG's recommendations into the proposed Early Adopter subcategory, that would:
    - allow facilities the option to either comply with the zero discharge limits no later than December 31, 2032, or avoid new ELG requirements by committing to repower or retire by December 31, 2035.

- **Maintain the 2020 Rule's Sound Determinations on Flue Gas Desulfurization (FGD) Wastewater Treatment.**
  - Maintain EPA's position that membrane filtration is not nationally available, economically achievable, or environmentally sound for covered units.
  - Maintain EPA's position that chemical precipitation plus biological treatment is best available technology economically achievable (BAT), not membranes, thermal evaporation, or other technologies.

- **Reevaluate, Revise, and Repropose Combustion Residual Leachate (CRL) Limits.**
  - Repropose leachate requirements after EPA evaluates BAT for the complete population of potentially impacted landfills and impoundments.
  - Provide flexibility for landfills and impoundments nearing closure or recently closed or retired, especially if EPA proceeds based on chemical precipitation.
  - Recognize that other stringent technologies are not BAT for leachate because the record lacks sufficient information to support such a determination.

- **Recognize that BAT Determinations Apply only to Direct Surface Water Discharges.**
  - ELG rules are inherently designed to address effluent discharges via outfalls into surface waters; releases into groundwater are subject to separate requirements.
  - BAT determinations do not logically apply to indirect discharges via groundwater to waters of the United States and should not be part of this rule.
    - If EPA proceeds with addressing groundwater issues in the ELG rule, it must address fundamental problems with applying the National Pollutant Discharge Elimination System (NPDES) permit program to these types of releases.

- **Maintain the 2020 Rule's Sound Determinations on Bottom Ash Transport Water (BATW).**
    - Maintain EPA's 2020 determination that a high recycle rate BATW system with a limited purge is the appropriate model technology for BAT limits for BATW.

- **Do Not Apply New ELG's Retroactively to Legacy Wastewater.**
    - EPA should not apply new ELGs retroactively to discharges associated with wastewater that was generated prior to the new ELGs' effective date.
    - EPA should not specify a nationwide technology basis for legacy wastewater if EPA's new ELG applies to wastewater generated before the applicability date.

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Acronyms

ACRONYM	DEFINITION
2030 Baseline	IPM 2030 Pre-Inflation Reduction Act 2022 Reference Case
AMWA	Association of Metropolitan Water Agencies
APA	Administrative Procedure Act
ASAP	as soon as possible
AWWA	American Water Works Association
BA	bottom ash
BAT	best available technology economically achievable
BATW	bottom ash transport water
BCT	best conventional technology
BOD5	biochemical oxygen demand
BPJ	best professional judgment
BPT	best practicable control technology
CAA	Clean Air Act
CBI	confidential business information
CCR	coal combustion residual
CP+LRTR	chemical precipitation followed by a low hydraulic residence time biological reduction treatment
CPCN	Certificate of Public Convenience and Necessity
CRL	combustion residual leachate
CWA	Clean Water Act
DESC	Dominion Energy South Carolina
EDR	electrodialysis reversal
EGU	electric generating unit

ACRONYM	DEFINITION
ELGs	effluent limitations guidelines
EPRI	Electric Power Research Institute
ERCOT	Electric Reliability Council of Texas
ERG	Eastern Research Group, Inc.
ESA	Endangered Species Act
FATW	fly ash transport water
FERC	Federal Energy Regulatory Commission
FGD	flue gas desulfurization
FGDW	flue gas desulfurization wastewater
FIP	Federal Implementation Plan
FOIA	Freedom of Information Act
GHG	greenhouse gas
gpd	gallons per day
gpm	gallons per minute
Gw	gigawatts
IPL	Indianapolis Power & Light
IPM	Integrated Planning Model
LRTR	low hydrologic residence time biological reduction
LWW	legacy wastewater
MATS Rule	Mercury and Air Toxics Standard regulations
MCL	maximum contaminant level
MDL	method detection limit
MDS	mechanical drag system
MISO	Midcontinent Independent System Operator

ACRONYM	DEFINITION
MWh	megawatt hour
NARUC	National Association of Regulatory Utility Commissioners
NEEDS	National Electric Energy Data System
NERC	North American Electric Reliability Corporation
NLT	no later than
NOPP	Notices of Planned Participation
NPDES	National Pollutant Discharge Elimination System
NSPS	new source performance standards
O&M	operating and maintenance
OMB	Office of Management and Budget
ORSANCO	Ohio River Valley Water Sanitation Commission
PFAS	per- and polyfluoroalkyl substances
PP15	Preliminary Effluent Guidelines Program Plan 15
ppm	parts per million
PRA	Paperwork Reduction Act
PSC	public service commission
PUC	public utility commissions
RCRA	Resource Conservation and Recovery Act
RML	reference margin level
RO	reverse osmosis
RPA	reasonable potential analyses
RTO/ISO	transmission organization/independent system operator
SCC	state corporation commission
SDE	spray dryer evaporator

ACRONYM	DEFINITION
SGC	submerged grind conveyer
TBELs	technology-based effluent limitations
TDS	total dissolved solids
TSS	total suspended solids
TTHM	total trihalomethanes
TWF	toxic weighting factor
TWPE	toxic-weighted pounds-equivalent
UWAG	Utility Water Act Group
VIP	Voluntary Incentives Program
VSEP	vibratory shear enhanced process
WV PSC	West Virginia Public Service Commission
WQBELs	water quality-based effluent limits
ZLD	zero liquid discharge

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unworkable due to the additional costs of digging up and transporting the fly ash. These costs would add enormously to the costs of disposal.

3. EPA's analysis of whether membrane filtration/paste encapsulation is economically achievable is deeply flawed.

The many flaws in estimations of fly ash needed for brine encapsulation, fly ash sales forfeited, and the potential impacts on beneficial reuse of fly ash are reason enough to call into question EPA's conclusion that membrane filtration and paste encapsulation is BAT and is economically achievable. But these issues are just part of the story of EPA's failure to properly consider costs.

a. EPA's cost estimates fail to include some units that will continue to operate.

In reviewing EPA's estimates of individual generating unit costs, UWAG noted some apparent discrepancies. By all accounts, EPA expects units at Plants Bowen, Cardinal, and Ghent to continue operating; therefore, under the Proposal's preferred option, they will need to install membrane filtration. EPA lists these plants as "discharging FGD wastewater after 2028."[106] It also calculates fly ash availability for purposes of brine encapsulation for each of these plants.[107] But in its compilation of generating unit level costs by option, EPA assigns zero costs to Bowen, Cardinal, and Ghent for Regulatory Option 3, which would require membrane filtration for FGDW.[108] The table below consists of all units that EPA has identified as having

[106] Memorandum from U.S. EPA, to Steam Electric Rulemaking Record – EPA-HQ-OW-2009-0819, Flue Gas Desulfurization Flow Methodology for Compliance Costs and Pollutant Loadings at 1 & 3, Tbl. 1, (Sept. 12, 2022), EPA-HQ-OW-2009-0819-9379 (DCN SE10287).

[107] EPA Feb. 27, 2023 Fly Ash Memo at 6, Tbl. 3 & 7, Tbl. 4, EPA-HQ-OW-2009-0819-9685 (DCN SE10242).

[108] Memorandum from U.S. EPA, to Steam Electric Rulemaking Record – EPA-HQ-OW-2009-0819, Generating Unit-Level Costs and Loadings Estimates by Regulatory Option for the

pollutant loadings for FGDW over 10 million pounds under the baseline and needing ZLD under Regulatory Option 3.[109] These units also would have 0 pounds of pollutants for FGDW under Regulatory Option 3. For some of these units, EPA estimates substantial capital costs under Regulatory Option 3 (ZLD), while for others (highlighted in yellow), EPA estimates $0 capital costs.[110]

Unit	Capital Cost Under FGDW Regulatory Option 1 (Table 2 – CP+LRTR)	Pollutant Loadings Under Baseline for FGDW (lbs) (Table 11)	Capital Cost Under FGDW Regulatory Option 3 (Table 4 - ZLD)	Pollutant Loadings Under Regulatory Option 3 (Table 11)
Bowen3	$0	13,100,000	$0	0
Bowen4	$0	12,700,000	$0	0
Amos1	$0	48,800,000	$11,920,216	0
Amos2	$0	15,800,000	$51,115,293	0
Amos3	$0	11,400,000	$16,582,736	0
Elm RoadA	$0	11,000,000	$7,342,403	0
Elm RoadB	$0	11,000,000	$7,342,403	0
Seminole1	$0	14,900,000	$14,818,965	0
Big Bend4	$0	70,200,000	$63,519,045	0
Cardinal2	$0	11,500,000	$0	0
Cardinal3	$0	34,600,000	$0	0
Ghent1	$0	10,900,000	$0	0
Ghent2	$0	12,200,000	$0	0
Ghent3	$0	7,070,000	$0	0
Ghent4	$0	11,200,000	$0	0
Trimble1	$0	15,000,000	$9,036,763	0
TrimbleA	$0	106,000,000	$63,482,397	0
Mitchell1	$0	11,300,000	$10,388,325	0
Mitchell2	$0	11,300,000	$10,388,325	0

2023 Proposed Rule at 10, Tbl. 4 (Feb. 28, 2023), EPA-HQ-OW-2009-0819-9686 (DCN SE10381) (EPA Feb. 28, 2023 Costs & Loadings Estimates Memo).

[109] EPA Feb. 28, 2023 Costs & Loadings Estimates Memo at 10–13, Tbl. 4 & 50–53, Tbl. 11, EPA-HQ-OW-2009-0819-9686 (DCN SE10381).

[110] *Id.* at 10, Tbl. 4.

It is not clear why EPA estimates $0 capital costs for the facilities highlighted in yellow (Bowen, Cardinal, and Ghent). How does EPA expect these facilities to erase their pollutant loadings without any capital expenditures? Plant Bowen Units 3 and 4 are not retiring. EPA appears to have misinterpreted information about the potential retirement of Bowen Units 1 and 2 as indicating plans to retire Bowen Units 3 and 4, according to the document cited in its memo updating the industry profile.[111] For Cardinal, EPA appears to have concluded that an AEP announcement of reductions in its coal fleet meant it was retiring Cardinal Units 1, 2, and 3.[112] Buckeye Power has always owned Cardinal Units 2 and 3, while AEP owned Cardinal Unit 1. However, in August 2022, AEP sold Unit 1 to Buckeye Power. While Buckeye has filed a cessation NOPP for Unit 3, it plans to keep operating Units 1 and 2. As to Ghent, there is nothing in EPA's updated Industry Profile to suggest that the status of this plant has changed. LG&E/KU intends to continue operating Ghent Units 1, 3, and 4, and the Unit 2 decision will be based on Certificate of Public Convenience and Necessity (CPCN) approval. In sum, it appears EPA has miscategorized at least 7-8 units (two at Bowen, two at Cardinal, and three to four at Ghent). Since the Proposal finds that 22 plants would be subject to FGDW retrofits under the preferred regulatory option, adding three more plants to that list is a significant increase.

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[111] *See* Southern Company, Third Quarter 2021 Earnings Conference Call at slide 15 (Nov. 4, 2021), EPA-HQ-OW-2009-0819-9231 (DCN SE09636) (noting "potential" coal retirements by 2028).

[112] Sonal Patel, *AEP Will Shutter Nearly Half its Giant Coal Power Fleet—5.6 GW—by 2030*, POWER MAGAZINE (Nov. 10, 2020), EPA-HQ-OW-2009-0819-9099 (DCN SE09602) (claiming AEP planned to retire "Cardinal" in 2030. In fact, AEP sold Cardinal Unit 1 to Buckeye Power in August 2022.).

Additionally, EPA appears to have concluded that DESC's Williams Station is retiring prior to needing an FGD retrofit.[113] As already noted, the latest company IRP indicates otherwise. *See* note 62, *supra*. The IRP suggests that the retirement data of December 2030 is aspirational, as the text refers to the date as "the earliest" possible retirement date. IRP at 28. Therefore, EPA should assume that Williams will operate beyond 2032 and thus will need additional technologies to meet the Proposed Rule's requirements. Also, LG&E/KU plans to continue operating Mill Creek Units 3 and 4, but EPA has assigned zero costs for FGD retrofits to these units.[114]

At a minimum, EPA should explain its apparent oversight and recalculate the Proposal's estimated costs. Bowen Units 3 and 4 total 1,400 MWs, while Ghent is 2,225 MWs, and Cardinal Units 1 and 2 total 1,180 MWs. The costs of retrofitting these units for FGDW compliance under Option 3 will be substantial. EPA needs to add these units into its calculations and rerun all of its models to account for these additions and any other similar mistakes.

b. The record is not transparent, but it is clear that EPA has underestimated FGDW retrofit costs.

It appears EPA has based its costs for membrane filtration/paste encapsulation largely on aggregated vendor costs. The record is far from transparent in this area. EPA only provides generic cost curves and formulas for its calculations, without providing any data on the individual vendor estimates and with scant additional data used to develop the cost curves and formulas. For example, EPA lists the following components of its BAT technology (membrane filtration and paste encapsulation) in the 2023 TDD:

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[113] *See* Industry Profile Update at 6, Tbl. A-1, EPA-HQ-OW-2009-0819-9622 (DCN SE010241).

[114] EPA Feb. 28, 2023 Costs & Loadings Estimates Memo at 11, Tbl. 4, EPA-HQ-OW-2009-0819-9686 (DCN SE010381).

- chemical precipitation treatment equipment (equalization and storage tanks, pumps, reaction tanks, solids-contact clarifier, and gravity sand filter);
- chemical precipitation chemical feed systems (lime, organosulfide, ferric chloride, and polymers);
- chemical precipitation solids-contact clarifier to remove suspended solids;
- membrane filtration treatment equipment (membrane filtration, reverse osmosis, and storage tanks;
- brine encapsulation; and
- transportation and disposal of solids in a landfill.[115]

One might consider this a fairly detailed list of the components EPA is costing out to arrive at its estimates for membrane filtration and brine encapsulation. But this list and the rest of the 2023 TDD—including the section titled "Cost Methodology for Membrane Filtration"—do not clarify EPA's assumptions about, and estimates of, underlying costs. For example, what costs are included in "brine encapsulation?" If EPA is using a pumpable mixture, what size pipes and pumps are being costed out for the system? What length of pipe is EPA costing out, keeping in mind that power plants often have a fair amount of acreage and the nearest landfill may be located across the property from the FGDW treatment system? What amount of quicklime or other additives is EPA costing out for purposes of creating either a pumpable mixture or a truckable mixture? What size pugmill or other mixing equipment is EPA including in its estimate? How much redundancy is EPA planning for within these systems?[116]

[115] 2023 TDD at 36.

[116] EPA's 2020 cost methodology document for membrane filtration with paste encapsulation is of little help. Memorandum from Sara Bossenbroek & Danielle Stewart, ERG, to Steam Electric Rulemaking Record, Flue Gas Desulfurization Membrane Filtration with Encapsulation Cost Methodology (Aug. 7, 2020), EPA-HQ-OW-2009-0819-8695 (DCN SE08625). It lists certain components, such as "[p]umps" or "[p]iping (installed)," as included in the estimates, *id.* at 2, without providing any details of the number, size, or materials of construction. And EPA's 2020 "vendor-specific" cost methodology for membrane filtration with

Additionally, EPA's costs appear to be largely dependent on aggregated vendor-generated cost estimates that are used to generate cost curves for capital costs and O&M costs. The individual estimates provided by each vendor are not available for review, as they are deemed CBI, and so it is not clear how EPA aggregated those estimates to arrive at its cost curves. It is also not clear if the vendor estimates were actually comparable and included all ranges of costs. However, from recent experience with EPA's similar estimates in the 2020 Rule, we believe EPA is greatly underestimating the costs of membrane filtration and paste encapsulation.

As an illustration of how this process results in underestimates of costs, we can review EPA's estimated costs for CP+LRTR in the 2020 Rule and compare it to actual estimated costs for biological treatment alone (*i.e.*, not including any adjustment for chemical precipitation) that UWAG members have incurred or reported to their regulators.

encapsulation is confidential business information (CBI) and therefore not available to the public. ERG, Flue Gas Desulfurization Membrane Filtration with Encapsulation Vendor-Specific Cost Methodology (posted Aug. 31, 2020), EPA-HQ-OW-2009-0819-8918 (DCN SE08596).

Cost Comparison for Installing Treatment Technology
To Satisfy the FGD Wastewater Limits in the 2020 Rule

Plant Name (Units)	EPA Estimated Costs for Biological Treatment + Adjustment for Chemical Precipitation (Pre-tax 2018 dollars)[117]		UWAG Member Estimated Costs for Biological Treatment ($)	
	Capital	O&M	Capital	O&M
Fort Martin (Units 1 and 2)[118]	10,997,849	576,766	45,597,126	553,000
Trimble County (Units 1 and 2)[119]	12,785,392	1,535,726	64,800,000	3,085,416
Mill Creek (Units 1-4)[120]	5,560,844	442,871	68,000,000	3,069,562
Ghent (Units 1-4)[121]	9,068,391	741,951	70,200,000	4,215,581
Mitchell (Units 1 and 2)[122]	13,463,922	--	48,811,000	--

In the 2023 Proposal, EPA continues to understate the estimates for chemical

[117] Memorandum from Eastern Research Group, Inc., to Steam Electric Rulemaking Record, Generating Unit-Level Costs and Loadings Estimates by Regulatory Option at 30–37, Tbl. 5 (Generating Unit-Level Costs for FGD Wastewater Treatment under Regulatory Option B) (Aug. 31, 2020), EPA-HQ-OW-2009-0819-8934 (DCN SE08638) (ERG Costs and Loadings Memo). EPA calculated a treatment-in-place adjustment to estimate the capital and O&M costs that would be incurred by plants that already operate some components of the model chemical precipitation treatment system. *See* EPA, Supplemental Technical Development Document for Revisions to the Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category, EPA-821-R-20-001, at 5-25 to 5-26 (Aug. 2020), EPA-HQ-OW-2009-0819-8935 (DCN SE08650) (2020 TDD).

[118] Monongahela Power Petition for Approval at Exhibit DVS-1, page 2 of 2.

[119] Conroy Ky. PSC Testimony, Exhibit RSS-2 at 15, 27. Estimated capital costs for Trimble County have changed since the March 31, 2020 filing. Capital costs in this chart have been revised accordingly to reflect more accurate internal company estimates.

[120] *Id.*, Exhibit RSS-2 at 36, 48. Estimated capital costs for Mill Creek have changed since the March 31, 2020 filing. Capital costs in this chart have been revised accordingly to reflect more accurate internal company estimates.

[121] *Id.* at Exhibit RSS-2 at 57, 70. Estimated capital costs for Ghent have changed since the March 31, 2020 filing. Capital costs in this chart have been revised accordingly to reflect more accurate internal company estimates.

[122] Direct Testimony of Brian D. Sherrick on behalf of Appalachian Power Company and Wheeling Power Company, Company Exhibit BDS-D3 (W. Va. PSC undated).

precipitation and biological treatment. As an example, in the table below are EPA's plant-level calculations of costs for Ft. Martin to comply with the 2020 Rule by installing partial pretreatment and a SeHawk bioreactor. Despite EPA's adjustment to 2021 dollars, Ft. Martin's actual capital costs are still more than ***three times higher than EPA's estimate***, while EPA's O&M costs are higher than Ft. Martin's estimated O&M.

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Treatment System[123]	EPA Cost Estimates Capital (2021$)	EPA Cost Estimates O&M (2021$)
Partial pretreatment	4,791,710	110,039
SeHawk bioreactor	7,272,181	619,201
Total	**12,063,891**	**729,240**

For membrane filtration/paste encapsulation costs, the differences between EPA's estimates and industry estimates are also very significant. For example, Alabama Power obtained a site-specific estimate for retrofititting membranes plus pretreatment at Miller Units 1–4. The estimate is $279 million in capital costs, with annual O&M costs of $10.3 million. In contrast, EPA estimated only $18.7 million in capital costs for Miller to retrofit membranes, with estimated O&M costs of less than one million.[124]

EPRI has provided very detailed, well-documented capital and O&M cost estimates for membrane filtration and paste encapsulation at each of the 22 plants that EPA has identified as needing FGD retrofits under the proposal.[125] EPRI Comments at 32–35 and Tbl. 2-2. EPRI went to lengths to makes its costs comparable to EPA's. For instance, like EPA, it made the following assumptions:

- The three plants opting into the 2020 Rule's VIP received zero costs.
- The remaining 22 plants are assumed to have chemical precipitation and biological treatment in place.
- The assumed capital costs are those required to convert each plant from chemical precipitation and biological treatment to chemical precipitation, membrane filtration, and brine encapsulation.

[123] EPA, FGD Wastewater Proposed Rule Cost Database, EPA-HQ-OW-2009-0819-9955 (DCN SE10416).

[124] EPA Feb. 28, 2023 Costs & Loadings Estimates Memo at 14–15, Tbl. 5., EPA-OW-2009-0819-9686 (DCN SE10381).

[125] EPRI's objective was to describe its cost methodologies in detail, and it does so through extensive appendices attached to its comments. These appendices deserve careful review and comparison to EPA's methodologies.

Despite these similar baseline assumptions, EPRI's capital cost estimates are eight times higher than EPA's for the industry as a whole, and its O&M cost estimates ***are a staggering 41 times higher than EPA's.*** In evaluating total annualized costs, EPRI's estimate of industry costs is 25 times higher than EPA's estimate. *See* id. at 32–35, 39.

In analyzing these very significant differences in estimates, EPRI points to several key parameters.

First, EPRI believes that EPA should have used FGD peak flow, instead of a lesser, "optimized" flow, to estimate capital costs. EPRI's choice of peak flow rate makes sense because "treatment systems must be able to treat to compliance levels at all operating flow conditions." EPRI Comments at 39.

Second, EPRI's estimates include a redundant equipment train for the membrane filtration system, which is necessary because membranes must be taken out of service for frequent cleanings. *Id.*

Third, EPRI believes EPA should be using the FGD purge flow rate instead of an optimized flow to estimate O&M costs. *Id.* at 41. Apparently, EPA used an optimized flow as the basis for developing O&M costs for brine management. But as EPRI points out, using an optimized flow assumes that the flow will be cycled up, leading to higher chloride and TDS concentrations. However, cycling up is not feasible, in EPRI's judgement, for membrane systems because the higher TDS concentrations "leads to a greater tendency for membrane scaling and lower membrane system percent recovery." *Id.* For this reason, EPRI believes EPA should use the FGD purge flow rate for all O&M estimates.

Fourth, it is critical to the cost estimates to assume a membrane recovery rate that can be consistently achieved across the industry. *Id.* at 42. EPRI used a 70 percent membrane recovery

in its estimates. But as shown in the EPRI Comments, some of EPA's assumptions regarding the amount of fly ash needed to encapsulate brine indicate much higher percent recovery rates, ranging from 94.7 percent to 99.0 percent. EPRI Comments at 7.

EPA's lack of transparency on costs is detrimental to the public's interest in understanding EPA's approach to costs of the rule. Members of the public deserve to understand not just what the final numbers are, but also how those numbers relate to important underlying factors and to the realities of their own sites. This lack of transparency has hindered UWAG's ability to compare industry-generated costs to EPA's costs. As these comments have pointed out, there are several significant issues with the way EPA has estimated certain factors that contribute to costs of membrane filtration and paste encapsulation, such as:

- EPA's very significant underestimation of fly ash necessary to encapsulate brine from membrane filtration;
- EPA's use of a value related to brine generated from a thermal evaporator system to estimate brine generated from a membrane filtration system;
- EPA's severe underestimation of the number of plants that will have sufficient fly ash to use in encapsulating brine;
- EPA's erroneous conclusion that there will be a minimal impact to the fly ash beneficial reuse market from the necessary diversion of fly ash for use in brine encapsulation;
- EPA's failure to account for costs attributable to some units that will continue to operate; and
- the very significant underestimations of capital and O&M costs for retrofitting membrane filtration for all units.

These problems with EPA's proposal, taken collectively, are enough to warrant EPA's reconsideration of the regulatory models used in the Proposal. UWAG urges EPA to take the necessary steps for a proper analysis of each listed issue and to work with industry to understand the real costs of the Proposal.

c. EPA has failed to account for stranded costs from 2020 Rule compliance.

In addition to underestimating technology costs, EPA appears to ignore the financial issues created for industry members when new pollution control equipment, such as biological reactors, must be scrapped and replaced within a few years of their deployment. Typically, EPA does not revisit an industry with a recent revision of its effluent guidelines. The Agency tends to wait about seven years before considering whether the industry is again ripe for a revision of its ELGs. But when the Agency returns to the same industry for another round of ELG revisions within a three-year period, the result will be stranded assets and stranded costs. In early 2021, rather than stay the 2020 Rule while reconsidering it, EPA explicitly stated that facilities remained subject to the 2020 Rule and instructed permitting authorities to continue to implement the 2020 Rule. 86 Fed. Reg. at 41,802. As a result, many companies have continued to plan, design, engineer, and install technologies, including complex systems such as CP+LRTR and technologies to minimize BATW purge, to ensure compliance with the 2020 Rule.

If facilities now must replace those technologies with new technology to meet the Proposed Rule's ZLD requirements for BATW and FGDW, they will not be able to fully amortize their investments in 2020 Rule technologies. For example, to employ membrane filtration/paste encapsulation (EPA's preferred option), a facility would have to abandon use of its LRTR well before the end of the system's useful life and well before the end of its amortization period. EPA should take into account these stranded costs when evaluating the overall economic impact of its Proposal.

B. Chemical Precipitation Plus Biological Treatment—Not Membranes, Thermal Evaporation, or Other Technologies—Is BAT for FGDW.

In addition to membranes, EPA asks the public to assess the applicability of many other technologies to FGDW. None of the other "zero discharge" technologies EPA lists (thermal

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EXHIBIT 14

United States
Environmental Protection
Agency

Response to Public Comments for Supplemental Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category

April 2024

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U.S. Environmental Protection Agency
Office of Water (4303T)
1200 Pennsylvania Avenue, NW
Washington, DC 20460

Docket EPA-HQ-OW-2009-0819
www.regulations.gov
DCN SE11794

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Appendices

Appendix A: Comment Submittal Index Listing the Comment Submittals Ordered by Affiliate

List of Abbreviations

ACE	Affordable Clean Energy
BA	bottom ash
BAT	best available technology economically achievable
BATW	bottom ash transport water
BCA	Benefit and Cost Analysis
BMP	best management practice
BOD	biochemical oxygen demand
BPJ	best professional judgement
CA	combined ash
CAA	Clean Air Act
CBI	confidential business information
CCR	coal combustion residuals
CFR	Code of Federal Regulations
CH_4	methane
CO_2	carbon dioxide
CP	chemical precipitation
CPP	Clean Power Plan
CRL	combustion residual leachate
CSAPR	Cross-State Air Pollution Rule
CSC	compact submerged conveyor
CUR	capacity utilization rates
CWA	Clean Water Act
CWT	centralized waste treatment
DOE	Department of Energy
EA	Environmental Assessment
EDR	electrodialysis reversal
EGU	electric generating unit
EIA	Energy Information Administration

EJA	Environmental Justice Analysis
ELGs	effluent limitations guidelines and standards
EPA	U.S. Environmental Protection Agency
EPRI	Electric Power Research Institute
FA	fly ash
FBR	fluidized bed reactor
FGD	flue gas desulfurization
FGMC	flue gas mercury control
FO	forward osmosis
gal	gallon
GHG	greenhouse gas
GPD	gallons per day
GPM	gallons per minute
HAP	hazardous air pollutant
HRR	high recycle rate
HRT	hydraulic residence time
HRTR	high residence time reduction
HVAC	heating, ventilation, and air conditioning
ICR	information collection request
IPM	Integrated Planning Model
kWh	kilowatt-hour
L	liter
lb	pound
LRTR	low residence time reduction
LUEGU	low utilization electric generating unit
MATS	Mercury and Air Toxics Standards
MDS	mechanical drag system
mg	milligrams
MGD	million gallons per day

MGY	million gallons per year
mi	mile
µg	micrograms
MW	megawatts
MWh	megawatt-hours
N_2O	nitrous oxide
NA	not applicable
NAAQS	National Ambient Air Quality Standards
NERC	North American Electric Reliability Corporation
NOPP	notice of planned participation
NO_X	oxides of nitrogen
NPDES	National Pollutant Discharge Elimination System
NSPS	new source performance standards
NWQEI	non-water quality environmental impacts
O&M	operation and maintenance
OLEM	Office of Land and Emergency Management
ORCR	Office of Resource Conservation and Recovery
PM	particulate matter
POTW	publicly owned treatment works
PSES	pretreatment standards for existing sources
PSNS	pretreatment standards for new sources
QA	quality assurance
QC	quality control
RCRA	Resource Conservation and Recovery Act
RIA	Regulatory Impact Analysis
RO	reverse osmosis
SDE	spray dryer evaporator
SO_2	sulfur dioxide
TCLP	toxicity characteristic leaching procedure

TDD	Technical Development Document
TDS	total dissolved solids
TMT	trimercapto-s-triazine
TPY	tons per year
TSS	total suspended solids
VIP	Voluntary Incentives Program
WOTUS	Waters of the United States
ZVI	zero valent iron

Introduction

This document provides responses to all significant comments submitted on the EPA's proposed effluent limitations and guidelines rule for the Steam Electric Power Generation Point Source Category. The EPA's proposal was published in the Federal Register on March 29, 2023 (88 FR 18824) and the public comment period closed on May 30, 2023. This includes public comments received during two public hearings held by the EPA during the public comment period (April 20, 2023 and April 25, 2023).[1] The comments received during the public hearings overlap with the comments submitted to the docket and reviewed by the EPA as part of this rulemaking. Therefore, since the comments submitted to the docket that overlap with the comments submitted during the public hearing have been addressed, the EPA considers the public hearing comments to be addressed by this comment response document.

Submitted comments are available electronically through *https://www.regulations.gov* by searching Docket ID No. EPA-HQ-OW-2009-0819 and in hard copy at the EPA Docket Center Public Reading Room. The telephone number for the Public Reading Room is (202) 566-1744. The docket assigned a unique Document Control Number (DCN) to each comment submittal with the following format: EPA-HQ-OW-2009-0819-xxxxx, where the five digit number at the end is unique to that comment submittal. Where a commenter submitted more than one file, the EPA has included an attachment number, for example EPA-HQ-OW-2009-0819-xxxxx-A1 (A2, A3, etc.)

This document is organized into two parts as indicated in the Table of Contents below. To organize the comments and to facilitate the EPA's responses, the EPA classified comment submittals by topic, available in Part 1 of this document. If a specific comment submittal addressed multiple topics, the EPA subdivided the submittal by topic. Comments or portions of comments assigned to specific topics are referred to as "comment excerpts." All of the individual comment excerpts classified to a specific topic are reproduced within the comment code corresponding to that topic. Within a specific comment code, the comment excerpts are often sorted in order of the DCNs. However, comment excerpts may also be ordered within a specific comment code so that similar comment issues are grouped together. The EPA's responses to each comment code topic are available in Part 2 of this document. Similar to comment excerpts, the EPA's responses are organized by comment code. The Table of Contents provides a list of comment topics covered in Part 1 and Part 2 of this document.

To support the reader in finding and understanding the comments and their responses, the EPA has provided the following as part of this document:

- A listing of the major support documents for the rulemaking, referenced throughout the comment responses.
- Comment excerpts by comment topic (located in Part 1).
- Comment responses by comment topic (located in Part 2).
- A list of acronyms used throughout the comment response document.
- A comment submittals index ordered by Affiliate Name (and DCN) with the corresponding list of comment codes identified for topics covered in the comment submittal (Appendix A).

The EPA notes that many commenters raised the same, similar, or related issues. Therefore, the response to a specific code may refer the reader to other responses that provide additional details on a comment topic. While the EPA endeavored to be accurate and consistent in assigning comment excerpts to topics, and in referencing other relevant responses, some excerpts may have content that overlaps multiple topics. Accordingly, readers may find it helpful to read this entire document to obtain the EPA's response

[1] Available documents from each public hearing include the presentations given by the EPA and two transcripts. The documents are available at *https://www.regulations.gov*, see EPA-HQ-OW-2009-0819-10043 and EPA-HQ-OW-2009-0819-10044.

regarding a given general topic. Moreover, in many instances, particular responses presented in this document include references to other portions of the administrative record, including the preamble to the final rule and other major support documents for the rulemaking (see below). Accordingly, this document, together with the preamble and the rest of the administrative record should be considered collectively as the Agency's response to all of the significant comments submitted on the proposed rule.

Due to the volume of comments received, some responses in this document may not reflect the language in the preamble or final rule in every respect. Where the response is in conflict with the preamble or the final rule, the language in the final preamble and rule controls and should be used for purposes of understanding the scope, requirements, and basis of the final rule. Although portions of the preamble to the final rule are paraphrased in this document where useful to add clarity to responses, the preamble itself remains the definitive statement of the rationale for the final rule.

To locate other documents in the record, the reader should use the final rule record index. For information on the final rule record index and how to use it, see the Steam Record Index User's Guide.

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

- Technical Development Document for the Final Supplemental Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category (TDD), Document No. EPA-821-R-24-004.
- Environmental Assessment for the Final Supplemental Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category (EA), Document No. EPA-821-R-24-005.
- Benefit and Cost Analysis for the Final Supplemental Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category (BCA Report), Document No. EPA-821-R-24-006.
- Regulatory Impact Analysis for the Final Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category (RIA), Document No. EPA-821-R-24-007.
- Docket Index for the Revisions to the Steam Electric ELGs.

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PART 1. COMMENT EXCERPTS BY COMMENT CODE

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PART 2. COMMENT RESPONSES BY COMMENT CODE

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Reliability and Retirement Incentives

The EPA disagrees with comments suggesting that the EPA is using a combination of regulations to achieve generation shifting as discussed in Comment Code 1. Since the EPA has not established this subcategory to achieve generation shifting, no further response is necessary to comments suggesting such an approach is illegal under the CWA. Similarly, no further response is necessary to comments suggesting that the Agency select a different date for the permanent cessation of coal combustion to optimize the number of retirements.

The EPA also disagrees with the comment claiming that the EPA was using the subcategory to "avoid" the costs of compliance for a suite of technology options that are not economically achievable for the industry as a whole. When compared to the range of costs estimated for the final rule, the cost savings of the new subcategory are relatively modest. Furthermore, the EPA does not rely on costs as the primary rationale for subcategorization, but just as further support in the Agency's balancing of the statutory factors. For further discussion of the EPA's rationale, see Section VII.C.4 of the preamble.

PSES

The EPA acknowledges the site-specific circumstances raised by the lone indirect discharger of FGD wastewater with respect to IRA funds, DOE pilot project planning, and Illinois law. To the extent that none of these would impact the modeling assumptions that the Agency made in the baseline, no further response is necessary.

The EPA agrees with the commenter that the application of the early adoption subcategory in the PSES context differs but should still be permissible. The EPA has modified the requirements of the final subcategory such that, so long as the facility's treatment technology can meet the 2020 rule limitations, it can participate in the new subcategory.

ESA

The EPA disagrees with comments on ESA consultation as described in Comment Code 1.

9.c. Subcategorization – High Flow

The elimination of the high FGD flow subcategory is discussed in Section VII.C.1 of the preamble. The EPA disagrees with TVA that there is any legal or policy rationale for a subcategory that contains no facilities and, due to the passed 2023 availability timing, could never contain a facility in the future. To the extent that the EPA is already eliminating the subcategory, the Agency need not opine on the extent to which it could rely on costs so subcategorize a single facility. No further response is necessary.

10. Surface Impoundments

No excerpts in Comment Code 10.

11. FGD Wastewater - General

This comment code captures general comments on flue gas desulfurization (FGD) wastewater topics. More specific comments and responses on FGD related topics can be found in Code 12 (FGD Wastewater - Data), Code 13 (FGD Wastewater - Halogens), Code 14 (FGD Wastewater – Membrane Filtration), Code

15 (FGD Wastewater – Spray Evaporation and Thermal), and Code 16 (FGD Wastewater – Other Technologies). Topics in this code were organized into the following areas:

- General Profile and Cost Data
- Plant-Specific FGD Wastewater Operations
- Pretreatment Standards for Existing Sources (PSES)
- FGD Wastewater Best Available Technology Economically Achievable (BAT) – Zero Discharge
- FGD Wastewater 2020 Rule Costs and Implementation Timing
- 2020 Rule Voluntary Incentives Program (VIP)
- FGD Wastewater High Flow Subcategory
- General FGD Wastewater Cost Methodology
- Leasing Treatment Equipment
- Application to Other Wastestreams

General Profile and Cost Data

The EPA appreciates the costs analyses performed by one commenter. This subsection captures the EPA's response to the commenter's general costing analyses that apply to all FGD wastewater treatment technologies they evaluated in their comment letter appendices (i.e., FGD wastewater assumptions and inputs, cost methodology for brine encapsulation (referred to as solidification by the commenter), and summary of FGD wastewater industry cost methodology for zero discharge). The EPA's responses to the commenter's cost methodologies on membrane filtration and thermal technologies are captured in Code 14 (FGD Wastewater – Membrane Filtration) and Code 15 (FGD Wastewater – Spray Evaporation and Thermal).

FGD Wastewater Flow Rates

The EPA disagrees with the commenter's approach to use peak flows for sizing the FGD wastewater treatment equipment and annual average flows for estimating operations and maintenance (O&M) costs in their costing analyses. Estimating capital costs based on peak flows would result in a system that is unnecessarily oversized. For capital costs, the EPA used average purge flow rates to ensure that well-operated treatment systems would have enough capacity (including equalization) to handle high flow events.

The commenter used average annual flow rates to estimate O&M costs. However, the EPA used optimized FGD flow rates (that take into account a reduction in FGD wastewater purged from the system, where FGD system metallurgy allows) to estimate O&M costs in an effort to reflect likely operating conditions. The EPA confirmed that flow optimization is a reasonable step plants can take to minimize compliance costs using data collected during site visits, meetings with industry representatives, and other sources. At the time of the 2020 rule, the EPA was aware of at least two plants anticipating implementing flow optimization approaches as they upgrade their FGD wastewater treatment (see "Trimble County Generating Station Site Visit Notes" (DCN SE07143) and "Southern Plant Scherer Meeting Notes" (DCN SE08619)). For the 2024 rule, the EPA has maintained its approach of estimating O&M costs using optimized flow rates.

As described in the TDD and various cost methodology memoranda, the EPA developed cost methodologies that allow for transparency in both the flows used to estimate costs and the cost factors and equations used to estimate costs. See "Flue Gas Desulfurization Flow Methodology for Compliance Costs and Pollutant Loadings – 2024 Final Rule" memorandum (DCN SE11708) and "FGD Wastewater 2024 Final Rule Cost Database" (DCN SE11705). Where a commenter felt costs were not accurately estimated or flows were not reflective of the actual system operation, the opportunity to provide

comment and correct the EPA's estimates was available through the public comment process. For comments providing flow rates that differed from the EPA's FGD purge flow rates, the Agency revised those flow rates as provided by power companies in comments.

FGD Wastewater Quality

The commenter provided the assumptions of FGD wastewater quality for their FGD costing scenarios. The EPA's membrane filtration and spray dryer evaporator (SDE) cost estimates are based on treatment of an untreated FGD purge stream (see Table 6-3 of the 2015 rule TDD (EPA-HQ-OW-2009-0819-6432)); low residence time reduction (LRTR) O&M cost savings are based on treatment of chemical precipitation (CP) treated effluent concentrations (see Table 6-1 of the 2020 rule TDD (EPA-HQ-OW-2009-0819-8935) The EPA provided vendors with this data so that they could provide information on treatment steps that are necessary. Since the commenter did not use these same data, in the same way that the EPA did, their estimates for capital costs and O&M would be expected to be different from those developed by the EPA. The commenter did not provide information to suggest that the EPA's choice of data was unreasonable.

FGD Wastewater Cost Analysis Inputs, Fly Ash, and Brine Encapsulation

The EPA acknowledges the cost analyses performed by the commenter, specifically the FGD profile input, fly ash analysis, and brine encapsulation methodologies. The EPA's methodology for identifying the inputs for the FGD costing analyses is presented in Section 5 of the TDD. As described previously in this comment response, the EPA disagrees with the commenter's use of peak flow rates to estimate capital costs and annual average flow rates to estimate O&M costs for the reasons stated above. To the extent possible, the EPA made updates to the FGD flow rates if specific commenters provided updated flow rate information or announced changes in electric generating unit operations (i.e., retirement, refuel). The EPA did not use individual FGD wastewater quality for sizing solids dewatering equipment or disposal estimates (specifically TSS concentrations); the EPA estimated solids handling and disposal costs based on national averages, which are captured in the cost estimates the EPA presents in Section 5 of the TDD (which are based on flow rate inputs). The EPA expects that this may result in underestimates for some plants and overestimates for other plants, but overall results in a reasonable estimate to determine economic achievability.

For the specific updates that the EPA made to the fly ash availability estimates and brine management analyses in response to public comments, see responses to comments in Code 14 (FGD Wastewater – Membrane Filtration).

Industry Costs for FGD Wastewater – Thermal or Membrane Zero Discharge

The commenter provided a methodology for treating FGD wastewater with "chemical softening (CS) followed by seawater reverse osmosis and brine solidification." The EPA did not estimate costs or performance for this specific technology design for the final rule. There are many different treatment technologies (e.g., chemical softening, seawater reverse osmosis, brine solidification) by which zero-discharge limits can be achieved. The EPA did not evaluate all possible combinations of these treatment technologies. Rather, the EPA evaluated treatment technologies that have been the most widely demonstrated to be successful for achieving zero discharge. Since the commenter used a different treatment technology than the EPA, their estimates for capital costs and O&M will be different from the estimates developed by the EPA. However, while the EPA establishes limitations based on a model technology (or technologies), the Agency does not require the use of that technology. Instead, facilities may elect to utilize this technology if that technology allows them to meet the requirements of the 2024 Final Rule.

In addition to the individual case study costing analyses presented, the commenter also provided a summary of total industry costs for the treatment of FGD wastewater based on a selection of one of three zero discharge options: vapor-compression evaporation with crystallization, vapor-compression evaporation with brine solidification, and advanced membrane filtration with brine solidification. Based

on the availability of fly ash, the commenter selected the most likely system installation for the total industry cost estimate.

As described in section VII.B.1 of the preamble, the EPA also considered three zero-discharge technologies as the basis for BAT for FGD wastewater. More specifically, the technology basis for BAT is based on membrane filtration, SDE, and thermal evaporation, alone or in any combination, including any necessary pretreatment (e.g., CP) or post-treatment (e.g., crystallization). As described in Section 5 of the TDD, the EPA estimated FGD compliance costs for a plant based on the least cost option between membrane filtration and SDE (different zero-discharge technologies than presented by the commenter). In its costing analysis, the EPA did consider plant-specific fly ash availability, and where appropriate, accounted for the cost of additional fly ash or other additives to achieve the estimated brine encapsulation recipe.

The EPA notes that it did estimate costs for all three FGD zero-discharge technologies, individually and in various combinations; however, the plant-level cost estimates for thermal evaporation contain CBI and therefore cannot be released publicly. To increase transparency of this final rule, the EPA ran an alternative set of costs selecting the least-cost technology between only membrane filtration and SDE. The EPA found that only six plants would select thermal evaporation systems as the lowest cost option when all three technologies are considered.

Consistent with the commenter, the EPA found that not all plants have enough fly ash available to meet the brine encapsulation requirements and that the least cost technology option for several FGD plants may not be membrane filtration. The EPA is not comparing its total industry costs to the commenter's costs presented in Appendix F because the inputs (e.g., flow rates) and assumptions made (e.g., redundancy) are different and, therefore, a direct comparison would not be helpful.

Plant-Specific FGD Wastewater Operations

The EPA is not finalizing a subcategory that looks exactly like the proposed early adopter subcategory. See the Preamble Section VII.C.4 for details on the final subcategory for EGUs permanently ceasing coal combustion by December 31, 2034.

Winyah Generation Station is planning to permanently cease coal combustion before 2034; therefore, Winyah will only need to meet requirements for the 2020 rule, and the EPA estimates $0 in compliance costs for this plant.

The EPA agrees with the commenter that Marshall and Allen Steam Stations have $0 in compliance costs under the final rule.

Although Plant Bowen Units 1 and 2 have filed a notice of planned participation (NOPP) for the subcategory for EGUs permanently ceasing coal combustion by 2028, Southern Company's comment letter indicated that "[T]he Georgia PSC deferred a decision on the retirement of Plant Bowen Units 1&2 until the Georgia Power's next regularly scheduled Integrated Resource Plan (IRP) in 2025." (EPA-HQ-OW-2009-0819-10073-A1). Therefore, the EPA estimated non-zero compliance costs for Plant Bowen Units 1 and 2. For Plant Bowen Units 3 and 4 and Plant Miller Units 1-4, the EPA has also estimated non-zero FGD compliance costs. For generating unit-level costs by regulatory option, see the *Generating Unit-Level Costs and Loadings Estimates by Regulatory Option for the 2024 Final Rule* memorandum (SE11756).

The EPA updated the FGD purge flow rate for Dallman to 251,000 gallons per day (GPD). For the 2023 proposed rule, the EPA projected that there would be no remaining indirect dischargers of FGD wastewater. In response to this finding, City Water, Light and Power (CWLP) commented that it retains the option of either sending its treated FGD wastewater to the local POTW or directly discharging. The EPA takes CWLP at its word that it will continue to be an indirect discharger at least some of the time and updated its FGD cost and loadings analyses to reflect the plant as an indirect discharger.

Pretreatment Standards for Existing Sources (PSES)

The EPA disagrees with the commenter's request for no FGD PSES requirements in the final rule. See Section VII.D of the preamble for a further discussion on the EPA's rationale for establishing PSES limitations. The Act requires compliance with pretreatment standards no later than three years after promulgation. See Section VII.E of the preamble for details on the timing for PSES requirements.

The EPA is establishing PSES limitations for FGD wastewater based on zero-discharge technologies (see Section VII.D of the preamble). The EPA disagrees with the commenter that PSES requirements for FGD wastewater are not necessary because there is only one plant currently indirectly discharging FGD wastewater. While the EPA acknowledges that City Water, Light, and Power (CWLP) Dallman may be the only plant currently discharging FGD wastewater to a publicly owned treatment works (POTW), this does not preclude existing plants from becoming indirect dischargers in the future.

The EPA disagrees with the commenter that simply because only one plant currently discharges FGD wastewater indirectly this makes them fundamentally different from other plants or that their plant is "disproportionately impacted by the ELG rule." The EPA acknowledges the comments submitted by CWLP, in addition to the discussions it has had with the EPA during the development of this final rule. Consistent with the EPA's response to CWLP's public comments on the 2019 proposed rule, the EPA disagrees that their plant is disproportionately impacted. The commenter already has a chemical pretreatment system in place, and the EPA estimated compliance costs associated with the installation of a spray dryer evaporator to comply with the zero-discharge requirements. The EPA acknowledged this in its evaluation of the cost to meet the requirements of the final rule. The EPA incorporated the commenter's information on the industrial user rates charged by the POTW that it discharges to and updated that cost savings reflected in the membrane filtration cost methodology (see Section 5 of the TDD). The EPA found the costs of meeting BAT limitations and pretreatment standards on FGD wastewater based on zero-discharge system to be economically achievable, as that term is used in the CWA. See Sections VII and VIII of the preamble. The EPA also found that the PSES can be met three years after promulgation. See Section VII.E of the preamble.

The EPA disagrees that it should decline to adopt PSES for FGD wastewater because PSES is not necessary to achieve environmental benefit as applied to CWLP and its POTW. First, as described above, PSES apply to any existing plant that currently or in the future begins indirectly discharging FGD wastewater, not just to CWLP and its POTW. Refer to Code 1 (Legal Authority) for a response regarding why the EPA typically establishes PSES to achieve the same level of control as BAT limitations.

The commenter also states that "[a]s explained in 2020, SCWRD has no issues meeting the current ELG limits at the end of pipe, and this situation has only been enhanced by CWLP's progress in achieving the 2020 ELG limits prior to sending wastewater to the POTW." However, the EPA is not obligated to evaluate PSES for FGD wastewater based on one POTW's performance. *See Chem Mfrs. Ass'n v. EPA*, 870 F.2d 177, 247 (5th Cir. 1989) ("We hold that the EPA's decision to define pass through based on POTW average removal does not violate the CWA."). The EPA also disagrees that the plant is fundamentally different from other plants included in the EPA's analysis. There is no record evidence demonstrating that the commenter's plant, in terms of its FGD wastewater operations or CP pretreatment system, is fundamentally different from other plants in the EPA's analyses. And, as stated above, the EPA's evaluation of PSES is based on the indirect discharger, not the POTW (or the limits it can meet). Refer to discussion in Section VII.D of the preamble.

FGD Wastewater BAT – Zero Discharge

The EPA agrees with commenters that technologies other than membrane filtration are available to meet the zero-discharge limitations. As described in Section VII.B.1 of the preamble, the EPA is identifying zero-discharge systems as the technology basis for establishing BAT limitations to control pollutants discharged in FGD wastewater. More specifically, the technology basis for BAT is membrane filtration, SDE, and

thermal evaporation, alone or in any combination, including any necessary pretreatment (e.g., CP) or post-treatment (e.g., crystallization). Furthermore, where a permeate or distillate is generated from the final stage of treatment, the BAT technology basis uses a process wherein this water would then be recycled back into the plant either as FGD makeup water or boiler makeup water. The EPA acknowledges that the decision on treatment technology to install will be on a plant-specific basis.

Commenters requested clarification regarding the classification of permeate or distillate from treatment processes and whether further treatment of permeate or distillate prior to its use as FGD makeup water or boiler makeup water will not impact a plant's ability to achieve zero discharge. Permeate or distillate refers to the "clean" stream from a membrane filtration or thermal evaporation system. This stream can be reused with or without further treatment. Further treatment of this stream would not impact a plant's ability to achieve zero discharge, so long as waste from the treatment of this stream is not discharged. Commenters also requested clarification on RO reject and membrane filtration backwash rinse classification. These wastestreams are considered FGD wastewater and, therefore, must meet the final zero-discharge limitations in this rule.

Commenters are concerned that, given the lack of new information, the EPA has simply reinterpreted its conclusions from the 2020 rule regarding the availability of zero discharge technologies. See Section VII.B.1 of the preamble for the EPA's rationale on selecting zero-discharge technologies as BAT; see also response to comments in Code 1 (Legal Authority) regarding the sufficiency of the EPA's justification in light of findings in the 2020 rule. The EPA disagrees that membrane filtration is not available. See preamble section VII.B.1, as well as the EPA's response to Comment Code 14 (FGD Wastewater – Membrane Filtration).

The 2020 BAT limitations remain in place as interim BAT limitations, as explained in Section VII.C.7 of the preamble. The EPA has determined that those requirements are available and economically achievable. The EPA also determined that more stringent requirements are available and economically achievable, and it has finalized additional limits to be achieved no later than December 31, 2029, as described in Section VII of the preamble.

FGD Wastewater 2020 Rule Costs and Implementation Timing

In response to a commenter's concern that companies have "incurred significant expenses to meet the requirements of the 2020 Rule," and providing specific examples of some utilities that have taken steps to comply with the 2020 rule, the EPA notes that Plant Scherer opted into the 2020 Rule VIP and therefore will not need to meet the 2024 final rule limitations. Another commenter noted the example of Williams Station – Williams Station is retiring by 2034 and therefore will only be subject to the 2020 rule BAT limitations under the new subcategory for EGUs permanently ceasing coal combustion by December 31, 2034. This subcategory, which is based on the proposed early adopter subcategory, allows greater flexibility for plants that have taken steps to come into compliance with the 2020 rule to continue operating those treatment systems until refueling or retirement of its EGUs serviced by a wet FGD system. In addition, the EPA agrees that industry continues to fund pilot studies since the 2020 rule - this is a typical outcome of needing to install treatment technology to meet new limitations, and the EPA considers the cost of and duration to conduct pilot studies in its cost estimates. See the EPA's response to Code 14 (FGD Wastewater – Membrane Filtration) for additional discussion of costs incurred for previous rulemakings; see also the response to Code 1 (Legal Authority) regarding the EPA's consideration of reliance interests.

The EPA acknowledges that plants need adequate time to build in unforeseen delays such as supply chain and worker shortages, but it does not see the implementation deadline of December 31, 2029, as unreasonable. As the EPA states in the preamble (see section VII.E), there are several wastewater treatment vendors that can manufacture membranes as well as SDEs (refer to the *Technologies for the Treatment of Flue Gas Desulfurization Wastewater, Coal Combustion Residual Leachate, and Pond Dewatering – 2024 Final Rule* memorandum (SE11695)), and the EPA expects that plants can commission

treatment technologies within a permit cycle. Refer to Code 43 (Regulatory Implementation – Timing) for additional information.

Refer to Code 1 (Legal Authority) for the EPA's response to comments reliance interests.

With respect to grid reliability, the EPA does not find that this rule will result in grid reliability concerns as discussed in Section VII.C.4 and VII.F of the preamble.

Refer to Code 5 (Regulatory Options – Compliance Cost Methodology) for the EPA's response to comments on cost recovery.

2020 Rule VIP

As stated in Section XIV.B.1 of the preamble, the EPA did not propose, nor is the Agency finalizing, any changes to the existing 2020 rule VIP. This final rule does not impact dischargers choosing to meet the 2020 rule VIP effluent limitations for FGD wastewater; the date for meeting those limitations is December 31, 2028.

FGD Wastewater High Flow Rate Subcategory

The EPA disagrees with the commenter's assertion that it did not consider higher FGD wastewater flows from once-through or high-flow wet scrubbers to evaluate membrane filtration as BAT. The EPA discussed limitations of the treatment technology with vendors and incorporated cost estimates for a range of membrane flow rates into its costing analyses. As stated previously in this response, the EPA is identifying zero-discharge systems as the technology basis for establishing BAT limitations to control pollutants discharged in FGD wastewater. Specifically, the technology basis is membrane filtration, SDE, and thermal evaporation, alone or in any combination, including any necessary pretreatment (e.g., CP) or post-treatment (e.g., crystallization). The EPA also notes that both Cumberland and Kingston are slated to retire by 2028 and are, therefore, eligible for the EGUs permanently ceasing coal combustion by 2028 subcategory, which contains limits based on surface impoundments (see section VII.C.3 of the preamble).

FGD scrubbers with high purge flows are not fundamentally different from other scrubbers based on the CWA statutory factors, as discussed in the preamble in section VII.C.1s.. As stated in section VII.C.1 of the preamble, the EPA previously based the 2020 high FGD flow subcategory on the supposedly disparately high costs, not other engineering aspects, but this 2024 final rule does not contain a high FGD flow subcategory.

General FGD Wastewater Cost Methodology

See responses to comments in Code 7 (Industry Profile & Plant Operations) related to industry profile changes and incorporating new generating unit retirements into the population of steam electric plants.

Regarding comments on the EPA's FGD wastewater flow methodology, as described earlier in this comment response, the EPA does not use peak flow rates to estimate compliance costs. In addition, the EPA's flow methodology adjusts purge flows at the FGD system level, and the EPA disagrees with the commenter who suggested that FGD wastewater treatment costs do not reduce upon retirement or refueling of EGUs. Where systems service EGUs that are retiring or refueling, the EPA adjusts the system-level FGD purge flow rate to remove the contribution from those EGUs. The unit-level flow rates are then determined by multiplying the system-level purge flow by the ratio of the unit's generating capacity to the sum of generating capacities for all units serviced by the FGD system. Refer to the *Flue Gas Desulfurization Flow Methodology for Compliance Costs and Pollutants Loadings – 2024 Final Rule* (SE11708) for plant-specific details. Where commenters provided purge flow rates that differed from the EPA's estimate, the EPA adjusted the plant's flow rate for the final rule.

The EPA evaluated capital and O&M costs from membrane filtration vendors and ultimately took the average of this range for compliance cost estimation to protect confidential business information (CBI), as one commenter suggests. In response to public comments, the EPA did revise its cost methodology for membrane filtration, resulting in higher plant-level costs. See responses to comments in Code 14 (FGD Wastewater - Membrane Filtration) for additional details on comments specific to the following topics:

- Fly ash required for brine encapsulation, increased transportation and disposal costs, and impacts to beneficial reuse market.
- Estimating O&M costs for membrane filtration using optimized flows.
- Impacts of high chloride and/or TDS.
- Recovery rates of membrane filtration.
- Equipment redundancy.

Commenters state that membrane filtration costs underestimate costs associated with retrofitting. The EPA discusses plant-specific design considerations and how these are factored into the EPA's cost estimates in Code 14 (FGD Wastewater – Membrane Filtration).

One commenter provided their estimate of zero-discharge costs for Cross Generating Station that are based on bids received and noted that the bids were adjusted for submittal to the public docket with "additional estimates of construction cost and risk." The commenter further stated that the zero-discharge costs provided in the Cross estimate would also apply to Winyah Generating Station; however, this plant intends to retire or refuel all generating units by 2031 and, therefore, would qualify for the subcategory for EGUs permanently ceasing coal combustion by 2034 and would not be subject to the zero-discharge limitations of the 2024 final rule. The EPA notes that its final rule costing analyses assumed Cross Generating Station would comply with the 2020 rule VIP (based on a contingent Notice of Planned Participation (NOPP) filed in 2021); the EPA acknowledges this discrepancy in the memorandum *Updates to Estimated Compliance Costs and Pollutant Loadings* (DCN SE11780). In addition, without having the construction cost and risk factors explicitly given, the EPA is unable to make a direct comparison to the commenter's estimates. Another commenter provided their estimate for chemical precipitation and biological treatment costs for Fort Martin Power Station. Chemical precipitation capital and O&M costs or CP+LRTR capital costs are costs incurred as a result of the 2020 rule and are thus represented in the baseline analysis for this rule. The EPA finds that the costs of this rule, over and above costs in the baseline, are economically achievable for the industry, as required by the CWA. The EPA notes that the commenter's estimated biological treatment O&M costs are less than the EPA's CP+LRTR costs, which are considered in the final rule cost estimation and reflected as a cost savings. While the EPA recognizes that it may have underestimated compliance costs for some plants, it is also likely that the EPA overestimated costs for other plants. Overall, the EPA's cost estimates provide a reasonable estimate for purposes of determining economic achievability, as required by the CWA.

Leasing Treatment Equipment

The EPA received comments both for and against leasing equipment for the treatment of FGD wastewater. The EPA conducted an evaluation of leasing equipment in response to comments on the 2019 proposed rule. At that time, data were limited, but the EPA met with one utility that had evaluated leasing of treatment equipment and several vendors that provide this service. The EPA used the information provided about this plant to evaluate leasing in *Cost to Lease Flue Gas Desulfurization Wastewater Treatment* memorandum (DCN SE08633). No new data were provided specific to costs of leasing equipment; therefore, the EPA continues to rely on the analysis completed in support of the 2020 rule. As described in Section VII.B.1 of the preamble, the EPA determined the final rule to be economically achievable, and the EPA expects plants to install technologies within the specified implementation timeline. The final rule does not prohibit industry from leasing wastewater treatment equipment if that is

determined to be appropriate for certain plant installations, which may result in lower costs than the EPA estimated for certain power companies.

Application to Other Wastestreams

One commenter suggested that using membrane filtration data from other steam electric wastestreams and other industrial wastestreams is "an insufficient basis for concluding that membrane filtration technology is BAT and does not meet the criteria for a 'detailed justification' that the Supreme Court's *Fox Television* decision demands." First, as the EPA describes in preamble Section VII.B.1, the final rule has a BAT basis of three zero-discharge technologies, not membrane filtration alone. Second, there are similarities between FGD wastewater and the non-FGD wastestreams described in the preamble, including high TDS concentrations, gypsum scaling potential, and high variability. Nonetheless, as the EPA describes in preamble Section VII.B.1, the EPA is not basing its BAT determination solely on application of treatment technologies to other wastestreams. The EPA finds that the zero-discharge technologies that make up the BAT technology basis for FGD wastewater are available and economically achievable. See also response to comments in Code 1 (Legal Authority) regarding the sufficiency of the EPA's justifications in this rule.

12. FGD Wastewater - Data

PFAS

The EPA agrees with commenters that PFAS discharges from steam electric power plants are best considered and managed by permitting or control authorities; however, the EPA disagrees that the only "significant source of PFAS at steam electric facilities is likely to be the intake water used within the plant and then discharged…" As explained in the Section XIV.D.2 of the preamble, permitting or control authorities may appropriately consider whether PFAS monitoring and any further restrictions (e.g., BMPs) would be appropriate at a given facility. This evaluation would take into account operations at the plant, including any firefighting foam used in exercises or actual fires at steam electric plants that could contain PFAS.

Operating Characteristics

The EPA partially agrees with the commenter that not all FGD scrubbers are designed to withstand identical maximum chloride concentrations due to the materials of construction. EPA's cost methodology considers plant-specific maximum design chloride concentrations when estimating the optimized FGD flow, see TDD Section 5.1 for more details. The EPA's methodology does not estimate that plants will recycle FGD wastewater beyond a plant-specific FGD scrubber design chloride concentration (based on materials of construction).

Regarding the commenter's plant-specific FGD scrubber chloride concentrations, the EPA notes that these may be different from other plants in the steam electric industry and that higher concentrations than those provided by the commenter may cause corrosion and scaling in those particular plants' scrubbers (Cumberland and Kingston); however, the EPA uses each plant's provided maximum design chloride concentration, either from the 2010 Questionnaire for the Steam Electric Power Generating Effluent Guidelines, public comments, or other industry-provided data sources, to estimate optimized flow rates (flow rates that are a result of cycling up chloride in the scrubber), and does not assume that all plants will cycle up to "much higher chloride concentrations ranging from 10,000 to 50,000 ppm." Refer to Code 14 (FGD Wastewater – Membrane Filtration) for the EPA's response regarding concerns from commenters on the impacts to membrane filtration treatment from cycling up chloride. The EPA disagrees with the commenter that CP provides adequate treatment of FGD wastewater and, as it did in the 2020 rule, the EPA rejected technologies less-stringent than zero-discharge technologies as BAT, as

discussed in Section VII of the preamble. The EPA continued to evaluate chemical precipitation as pretreatment for zero-discharge requirements.

Further, the EPA notes that the commenter provided plant-specific information for plants that are eligible for the EPA's Permanent Cessation of Coal Combustion (PCCC) by 2028 subcategory (Cumberland and Kingston). For EGUs in this subcategory, the EPA is also retaining the 2020 rule BAT limitations based on surface impoundments; therefore, the EPA does not expect these plants to cycle up their FGD scrubber operations nor to incur compliance costs as a result of this final rule.

POTW Removals

The EPA acknowledges the commenter's recommendation to update the POTW removal efficiencies using more recent data. The EPA estimates removals achieved by POTWs using the same median POTW removals it uses more generally in its Effluent Guidelines program (e.g., annual reviews, studies, and rulemakings). EPA has determined that these data, which are from 2005, are representative of discharges from well-operated POTWs, as POTWs are currently using similar treatment technologies. The EPA does acknowledge that some POTWs may be achieving better removals than the median used in EPA's estimates; however, some POTWs may also be achieving lower removals. While these median POTW removals may underestimate the concentration of some pollutants in the effluent, it may also overestimate the concentration for other pollutants or at other POTWs. The EPA expects that these median removals are a reasonable estimate of national POTW discharges.

In particular, the commenter noted median arsenic removals of 45%, median selenium removals of 60%, and median mercury removals of 50%. As presented in Section 6 of the TDD, EPA uses an arsenic removal of 65.8%, selenium removal of 34.3%, and a median mercury removal of 90.2%. Based on only these three pollutants, EPA's older data would appear to be over-estimating removals achieved by POTWs compared to the commenter's data. While this overestimation of POTW removals may also overestimate the removals of the Steam Electric ELG, it also results in estimating less POTW pass through than data cited by the commenter. Additionally, the current population of plants impacted by the Steam Electric ELG that discharges indirectly is small: less than 10 plants across FGD wastewater, BA transport water, CRL, and legacy wastewater.

13. FGD Wastewater - Halogens

The EPA disagrees with one commenter that "estimates of bromide in FGD (waste)water (and)…total pollution reduction calculations" are inflated and disagrees that "baseline loading should be adjusted such that bromide (max) values are equal to bromide (min) (i.e., loadings from native coal content and Br-AC) for all sites except for the two (plants) mentioned." As described in methodology memoranda,[21] EPA uses publicly available data to assign halogen use categories for each coal-fired power plant and generating units in the FGD loadings analysis. The publicly available data sources do not have corresponding data for specific halogen additive (i.e., bromine or iodine) used at each coal-fired power plant to reduce mercury emissions. Therefore, the EPA estimates potential ranges of bromide and iodine loadings in FGD wastewater. In addition, halogen loadings at a plant might fluctuate from one year to the next because plants may change their operating practices within that timeframe (e.g., burning/not burning refined coal or changes in application of bromide or other halogen salts). The loading estimates are based on a peer-reviewed methodology that has been used for multiple publications, literature data

[21] *See* ERG 2020 memoranda *Mass-Balance Approach to Estimating Bromide Loadings from Steam Electric Power Plants –DCN SE08957* and *Mass-Balance Approach to Estimate Iodine Loadings from FGD Wastewater – DCN SE08960* and U.S. EPA memoranda *FGD Halogen Loadings from Steam Electric Power Plants – 2024 Final Rule (DCN SE11703)*.

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sources that meet quality criteria, and publicly available plant-specific data where possible. The EPA acknowledges that actual bromide and iodine loadings will fall within this range of loadings.

The EPA also disagrees with one commenter's assertion that only two wet FGD plants use refined coal and will operate beyond 2028. The EPA used industry-reported data to the Energy Information Administration (EIA) to evaluate the types of coal burned by generating units serviced by wet FGD systems. For the 2024 final rule, the EPA used updated EIA data based on 2021 operations (baseline year for industry profile). According to the EIA data, 22 generating units with wet FGD systems at nine plants burned refined coal,[22] not just the two plants noted by the commenter. EPA reviewed EIA data based on 2022 operations and found that five of the nine plants reported burning refined coal. And, as noted above, operating practices that impact halogen loadings may change from one year to the next. Based on data collected for the industry profile, these generating units will continue to operate beyond 2028. Both Elm Road Generating Station and Muscatine Plant #1, as listed in the comment, are in this population of plants burning refined coal.

The EPA disagrees with commenters that its "documents indicate that most coal facilities use bromide additives" or that the Agency "(misunderstands) that bromide additives are still in use." As described in *FGD Halogen Loadings from Steam Electric Power Plants -- 2024 Final Rule* (DCN SE11703), the EPA assigned a halogen use category based on plant-specific data and plant-specific coal properties (i.e., native bromine concentrations in coal) as described in ERG's 2020 memoranda *Mass-Balance Approach to Estimating Bromide Loadings from Steam Electric Power Plants –DCN SE08957*. In its evaluation for the final rule, the EPA found that ten of the 25 plants discharging FGD wastewater do not add halogen additives. The EPA notes that the halogen used by the plant may be an iodine, not bromide, compound. Therefore, the EPA calculated a range of halogen loadings for the two pollutants. The EPA received one specific comment from a company regarding the use of bromide at its plants, and the halogen loadings reflect this comment's incorporation.

Regarding comments on Santee Cooper plants (Cross Generating Station), the EPA appreciates confirmation that this plant does not add bromide. At the time of the FGD halogen loadings analysis, the EPA had Cross Generating Station as a plant that elected to participate in the VIP program, therefore baseline and all technology option loadings for this plant are calculated as zero. After completing the loadings analysis, the EPA updated the industry profile to remove this plant as participating in the VIP program based on public comment (EPA-HQ-OW-2009-0819-10071-A1). The EPA estimated bromide loadings for this plant as a sensitivity analysis [see *FGD Halogen Loadings from Steam Electric Power Plants -- 2024 Final Rule* (DCN SE11703)].

The EPA did update the bromide loadings methodology based on public comment suggesting the use of 2019 EPRI report, *Impacts of Bromide from Power Plants on Downstream Disinfection Byproduct Formation: A Literature Review*, No. 3002017477. The EPA revised the equivalent bromine concentration in coal from refined coal burning and bromide additive use at the boilers to 120 parts per million (ppm) in calculations of the maximum bromide loadings. See the response to code 37 (EA – Halogens/Drinking Water Impacts) and *FGD Halogen Loadings from Steam Electric Power Plants -- 2024 Final Rule* (DCN SE11703).

The EPA acknowledges the support for EPA's proposed action. See the preamble for EPA's final action.

[22] At the time of the FGD halogen loadings analysis, the EPA determined that two of the nine plants elected to participate in the VIP program, and baseline and all technology option loadings for these two plants (six generating units) are calculated as zero. After completing the loadings analysis, the EPA updated the industry profile to remove one plant as participating in the VIP program based on public comment (EPA-HQ-OW-2009-0819-10071-A1). The EPA estimated bromide loadings for this plant as a sensitivity analysis [*see FGD Halogen Loadings from Steam Electric Power Plants -- 2024 Final Rule* (DCN SE11703)].

14. FGD Wastewater – Membrane Filtration

As described in Section VII.B.1 of the preamble, the EPA is identifying zero-discharge systems as the technology basis for establishing BAT limitations to control pollutants discharged in FGD wastewater. More specifically, the technology basis for BAT is membrane filtration, SDE, and thermal evaporation, alone or in any combination, including any necessary pretreatment (e.g., chemical precipitation) or post-treatment (e.g., crystallization).

As part of this rulemaking, the EPA has determined that membrane filtration is technologically available and economically achievable for use by the steam electric industry to control discharges of FGD wastewater. As described in more detail in the preamble, based on the EPA's current record, which contains additional information regarding the application of membrane filtration to FGD wastewater and other wastestreams inside and outside the steam electric industry, the Agency finds that membrane filtration is available to control FGD wastewater discharges, notwithstanding the uncertainties raised in the 2020 rule. Agencies have inherent authority to reconsider past decisions and to revise, replace, or repeal a decision to the extent permitted by law and supported by a reasoned explanation. *FCC v. Fox Television Stations, Inc.,* 556 U.S. 502, 515 (2009); *Motor Vehicle Mfrs. Ass'n* of *U.S. v. State Farm Mut. Auto. Ins. Co.,* 463 U.S. 29, 42 (1983). See Section VII of the preamble for more details.

The EPA received a variety of comments both for and against its inclusion of membrane filtration as part of the BAT technology basis. The EPA has organized comments in this code into six topic areas:

- FGD Membrane Filtration Costs
- FGD Byproducts
- Membrane Filtration – BAT
- Optimization Period
- Pilot Studies and Installations
- 2020 Rule

FGD Membrane Filtration Costs

Several commenters raised concerns about various aspects of the EPA's membrane filtration cost methodology, specifically the options the EPA evaluated for brine disposal, including brine encapsulation, crystallization, and deepwell injection. For the final rule, the EPA also evaluated costs for all plants discharging FGD wastewater to install SDE and thermal evaporation systems. As described in Section 5.1.6 of the Supplemental TDD, in the regulatory option cost estimate, the EPA selected either membrane filtration or SDE for each plant based on the least-cost option. However, each plant is free to choose the treatment technology or combination of technologies that is appropriate for their site and that achieves the final effluent limitations. One commenter provided their independent estimate of membrane filtration and three thermal evaporation technology options; the commenter did not estimate costs for SDE systems and, therefore, the EPA cannot make a direct comparison to its overall estimate. The EPA did estimate costs for thermal evaporation; however, due to claims by technology vendors, plant-level cost estimates are being held as confidential business information (CBI) and are not used in the least-cost estimates prepared using membrane filtration and SDE systems. Refer to Code 15 (FGD Wastewater – Spray Evaporation and Thermal) for more information.

Specific to the EPA's evaluation of brine encapsulation associated with membrane filtration, commenters raised the following issues:

- Plants allegedly not having enough fly ash and concerns over diverting fly ash from beneficial use or revenue from selling this material.

- The EPA's methodology allegedly uses an incorrect mixture of fly ash, brine, and lime.
- Costs for this technology are allegedly underestimated, both capital and operation and maintenance (O&M).

Based on some of these comments, the EPA has revised its methodology. In general, the EPA updated the methodology for estimating the amount of fly ash needed for encapsulation based on available information, including ratios of brine, fly ash, and lime (or other filler materials) and using a mass-based calculation for the solids generated by a membrane, as suggested by one commenter. See *2024 Steam Electric Supplemental Final Rule: Fly Ash Analysis* memorandum (SE11692) for additional details on the truckable brine recipe, as well as plant-specific results of fly ash availability. These changes resulted in increased capital and O&M costs due to the amount of solids that would require transportation and disposal following encapsulation, as well as additional fly ash purchase (as needed). Using this higher fly ash requirement and 2021 plant-specific data from U.S. Energy Information Administration (EIA) on amounts of fly ash generated, the EPA determined that nine out of 26 plants would require more fly ash than produced. Where additional fly ash was required, the EPA assessed O&M costs for the purchase of this material. The EPA did not consider fly ash stored on-site in its calculation of fly ash availability but notes that plants may choose to harvest landfilled ash for encapsulation and begin storing ash in anticipation of installing membrane filtration for FGD wastewater.

This update also resulted in increased non-water quality environmental impacts (NWQEI). Refer to the *Methodology for Estimating NWQEI for the 2024 Final Steam Electric ELGs* for additional details (SE11782). Commenters noted that the EPA had concluded for the 2020 rule revision that there were unacceptable NWQEIs if membrane filtration were to be selected as the BAT technology basis for FGD wastewater, due to diverting fly ash from beneficial reuse and concerns with landfilling the encapsulated material. As the EPA discusses in the preamble (see Sections VII.B.1 and X.C), the amount of fly ash sold for beneficial use fluctuates from year-to-year, but over the last five years, the amount sold would still be less than the amount available for sale even after assuming that every plant uses fly ash to encapsulate brine from an FGD wastewater and/or CRL treatment system. Thus, the EPA does not expect that, under worst-case scenarios, the use of fly ash to encapsulate brine would hamper the fly ash sales market. In addition, the EPA notes that the assumption that all plants will use membrane filtration and generate a brine for encapsulation represents a conservative estimate on fly ash usage. There are other technologies that can achieve zero-discharge limits (i.e., SDE, thermal). Thermal technologies produce much smaller volumes of brine that must be crystallized or encapsulated, and SDE systems generally do not produce any brine (dry byproduct). If plants choose to implement SDE or thermal technologies, which the Agency projects many will do as the least-cost alternative, there will be a smaller potential impact on fly-ash availability and usage.

The EPA received comments on the unknowns with the long-term stability of encapsulated material, stability of the landfill, and infiltration releases. In regards to the stability of the encapsulated brine, the EPA ensured that the brine recipes it used in estimating encapsulation transportation and disposal costs passed the Toxicity Characteristic Leaching Procedure (TCLP) test, paint filter liquids test, and/or the Synthetic Precipitation Leaching Procedure (SPLP) test and does not anticipate issues with landfilling approval; refer to the *2024 Steam Electric Supplemental Final Rule: Fly Ash Analysis* memorandum (SE11692) for additional details. Compared to traditional ash disposal methods, encapsulating the fly ash in brine results in fewer dust emissions (SE08036). With respect to the King George County Landfill leachate blowout, this scenario concerned a municipal solid waste landfill where that waste was mixed with CCR, a scenario that is only possible for facilities that use off-site disposal. While the EPA cost model projected nine facilities would select membrane filtration as the least cost technology, eight have on-site landfills. In addition, if plants have concern with their landfill's stability, they may opt for other brine management options, such as crystallization or deep well injection. See preamble Section VII.B.1 for more information on the EPA's response to comments regarding potential remobilization of pollutants from encapsulated brine and landfill liner compatibility.

The EPA evaluated EIA data to determine the amount of fly ash sold compared to the amount reported as total for the years 2017 through 2021; refer to the *2024 Steam Electric Supplemental Final Rule: Fly Ash Analysis* memorandum (SE11692) for additional details. This analysis again demonstrates variability in fly ash sales from year to year across the industry and within plants. Of the plants that specifically commented on not having sufficient fly ash for encapsulation and/or beneficial reuse, two plants are expected to retire or refuel all generating units by 2028 (and thus would not have to meet more stringent limitations under the 2020 or this 2024 final rule), one plant is expected to retire or refuel all generating units by 2034 (and thus would not have to meet more stringent limitations under this 2024 rule), one plant has sufficient fly ash for encapsulation, and five plants have sufficient fly ash to both encapsulate their brine and meet fly ash sales quotas based on 2021 EIA data (see Table 2 below). For the remaining four plants, the EPA estimated costs to purchase supplemental fly ash (SE11692).

Table 2. Fly Ash Availability for Brine Encapsulation and Beneficial Reuse

ICR ID	Plant Name	Commenter	Sufficient Fly Ash for Brine Encapsulation	Sufficient Fly Ash for Beneficial Reuse
265	Kingston	Tennessee Valley Authority (TVA)	Expected to retire/refuel by 2028	
771	Kyger Creek	Ohio Valley Electric Corporation (OVEC)	Yes	Yes
1236	Mitchell	American Electric Power (AEP)	Yes	Yes
1493	Plant Miller	Southern Company	Yes	Yes
2244	Plant Bowen	Southern Company	No	No
3235	Cross	Santee Cooper	Yes	No
3265	Cardinal	Buckeye Power, Inc.	Yes	Yes
4543	Mountaineer	AEP	Yes	Yes
5318	Clifty Creek	OVEC	No	No
6329	Cumberland	TVA	Expected to retire/refuel by 2028	
7411	Winyah	Santee Cooper	Expected to retire/refuel by 2034	
9161	Amos	AEP	No	No
9971	Dallman	City Water, Light and Power (CWLP), City of Springfield, Illinois	No	No

The demand for fly ash is not guaranteed for a particular location or plant. While there were plants in the EPA's analysis that did not have sufficient ash for beneficial reuse, there were also plants that have a surplus of ash, beyond the amount needed for encapsulation, as well as 2021 EIA fly ash sales; the EPA did not give these plants cost savings for the potential sales from this additional ash. In addition, there is fly ash available to the beneficial reuse market from plants that have "dry" FGD systems (i.e., do not generate slurry blowdown) and, therefore, are already meeting the ELGs. By using fly ash generated on site, plants can avoid the cost of purchasing additives to encapsulate brine. Furthermore, the EPA does not know definitively the amount of fly ash that will be required as it is variable depending on a plant's generation and corresponding flow rate for a given year. While the EPA acknowledges that diverting fly ash from beneficial reuse to membrane filtration brine encapsulation will reduce the amount of fly ash

available in the market, the EPA notes that plants may use other materials or technologies to encapsulate the brine or use thermal treatment technologies such as SDEs to meet the zero-discharge standard, as described more in Topic *FGD Byproducts*. Where a plant would need to purchase additional encapsulation materials, such as fly ash, the EPA found that, in all cases, the plant would use an SDE system in its least-cost option estimates and, therefore, would not install a membrane filtration system that might require fly ash for disposal of brine (refer to the Supplemental TDD Section 5.1 for more information on the least-cost option evaluation). Plants can also choose to use different recipes for encapsulating the brine produced by membrane processes that do not include fly ash.

One commenter provided their membrane filtration cost estimates for Plant Miller and Plant Bowen. For the Plant Miller cost estimate, the EPA notes that the commenter included the cost for a thermal evaporation system, in addition to membrane filtration and encapsulation; the EPA assumes this is a likely reason for the cost estimate being higher than the EPA's estimate; however, the commenter did not provide the purchased equipment cost for the membrane filtration equipment vs. the thermal evaporation equipment, so the EPA cannot make a direct comparison. As shown in Table 2, the EPA found that Plant Miller indeed has enough fly ash for membrane filtration brine encapsulation, and the EPA therefore estimated compliance costs for Plant Miller to install membrane filtration (without thermal evaporation). For this final rule, the EPA found that Plant Bowen does not have sufficient fly ash for encapsulation; the EPA found through its least-cost option estimate that membrane filtration was more expensive, and therefore estimated costs for the plant to install SDE. As the commenter did not provide an estimate for the plant to install the SDE technology, the EPA cannot make a direct comparison to its compliance cost estimate.

The EPA disagrees with commenters' assertion that the membrane filtration cost methodology uses an incorrect wastewater flow rate and that the membrane filtration system should include N+1 redundancy. Consistent with the costing approach from the 2020 Rule, the EPA's compliance cost estimates use the FGD average purge flow as the basis for capital costs; this ensures equipment is sized for a higher flow. O&M costs are based on the optimized flow as a closer approximation of costs incurred year to year. This approach sizes equipment for capital costs that incorporate a design capacity. The EPA disagrees that peak flow should be used to size equipment or estimate capital costs, as this would result in overly large equipment and inflate capital costs. Regarding redundancy, the EPA disagrees that N+1 is appropriate, where N is the peak flow. Based on the EPA's record, in practice, plants do not install entirely redundant treatment systems or even entirely redundant power generation equipment. Costs provided by vendors do include costs for redundant pumps. Vendors also noted that membrane systems are modular, so often an entirely redundant system is not required. If one module is taken down for service, either flow can be temporarily reduced, or other modules can take on additional flow temporarily (SE06930). In addition, the EPA supplemented one of the vendor cost estimates with additional flow equalization/storage tanks that may be used while the system is offline for maintenance. The EPA expects that the capacity of the chemical precipitation pre-treatment system will be similar to the design capacity of the membrane filtration system, and again notes that extra storage tanks may be used in times where the flow capacity of the membrane filtration system is exceeded.

The EPA acknowledges general comments that increasing concentration of chloride in the FGD scrubber system may increase total dissolved solids (TDS) concentrations in the blowdown, which could potentially reduce the percentage of treated water the membrane recovery process produces from the wastewater being treated. However, the EPA maintains that the average percentage of treated water produced being used in the EPA compliance cost estimates (70%) is reasonable, since the 70 percent treated recovery value agrees with the industry average value for recovery of treated water cited by one of the commenters. One membrane filtration vendor whose costs are included in the EPA's methodology specifically noted having included metallurgy that is compatible with high chlorides. Refer to Topic *Pilot Studies and Installations* for additional details.

The EPA also disagrees with commenters' statements that the EPA assumed 94.7-99% overall membrane recovery in developing its membrane filtration compliance cost estimates. The EPA's cost methodology

(SE11757) has consistently used an average recovery from treatment vendors of about 70%, as recommended by commenters. This recovery rate is applied to the optimized FGD wastewater flow to estimate the amount of permeate and the amount of brine factored into residuals treatment, disposal costs, and NWQEIs. The EPA acknowledges the special considerations in implementing Flex EDR[23] for treatment of FGD wastewater, such as pretreatment requirements; however, the EPA did not include this particular technology in its BAT technology basis nor its cost methodology. In addition, while constituents such as halogens, nitrate, or boron may lead to lower membrane recovery or boiling point rise in thermal evaporation treatment systems, as one commenter suggests, each plant will have unique wastewater characteristics and may, therefore, want to conduct a pilot study to optimize treatment, as described in Topic 5 *Pilot Studies and Installations*. The EPA did not include the cost for conducting a pilot study in its cost estimates, as none of the technology vendors included pilot testing in their cost estimate and none have stated that pilot studies would be needed; one technology vendor specifically stated that, given their experience to date with pilot testing, it is not required, but it can be conducted if requested by the plant. Merrimack Station, cited by the commenter, still achieves zero discharge of FGD wastewater, according to its 2020 NPDES permit.[24]

One commenter asserted that the EPA has not accounted for the higher annualized costs for plants that will cease coal combustion in less than 20 years. As stated in RIA Section 3.2.3:

> EPA assumed that the equipment installed to meet any new limitations could reasonably be estimated to operate for 20 years or more, based on a review of reported performance characteristics of the equipment components. EPA also determined the 20-year annualization period to be reasonable for this analysis because some regulators may allow utilities to recover the value of undepreciated assets in their rate base on a case-by-case basis. EPA thus used 20 years as the basis for the cost and economic impact analyses that account for the estimated operating life of compliance technology. To the extent that the actual service life is longer or shorter than 20 years, costs presented on annual equivalent basis would be over- or under-stated. This includes cases where a plant upgrades treatment technologies to comply with the ELGs but ceases operating before the 20-year life of the equipment.

Other commenters assert that membrane filtration is not economically achievable due to impact on plant revenue. The EPA determined that zero-discharge limitations are economically achievable, as discussed in Sections VII and VIII of the preamble. See also the *Regulatory Impact Analysis for Final Supplemental Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category* (RIA) (SE11107) for additional details.

The EPA acknowledges the errors in its memorandum *Generating Unit-Level Costs and Loadings Estimates by Regulatory Option for the 2023 Proposed Rule* (SE10381), where several EGUs mistakenly had zero costs; however, the EPA used the correct costs in its engineering, economic, and environmental assessments for both the proposed and final rules, and these errors have been corrected in the final rule memorandum, *Generating Unit-level Costs and Loadings Estimates by Regulatory Option for the 2024 Final Rule* (SE11756).

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[23] Electrodialysis Reversal (EDR), a membrane filtration technology, uses an electrical current passing between electrodes in the water (SE11781). Ion selective membranes between the electrodes allow either positive or negative charged ions to move to the oppositely charged electrodes across the membranes leaving treated water behind. The current is reversed at intervals to minimize scaling problems at the electrodes. Flex EDR is a proprietary technology from Saltworks Technologies that uses membranes that are specific for various ions (SE11695).

[24] After the EPA completed final rule analyses, Granite Shore Power announced that Merrimack Station would voluntarily retire (refer to preamble Section VII.C.2).

Several commenters raised concerns over site-specific scenarios that may result in increased costs. The EPA acknowledges that specific design considerations may be needed on a site-by-site basis. The EPA included contingency costs to cover these types of considerations. The EPA expects that some plants may need the full amount included as contingency costs due to unique site situations, but other plants may not use any contingency costs. The EPA assumes that across the industry, these overestimates and underestimates still result in an overall reasonable estimate of costs to the industry as a whole.

The EPA agrees with commenters' statements that, when evaluating the economic achievability of membrane filtration, the EPA must consider the full costs of membrane filtration technology, including pretreatment, the technology for solidifying and encapsulating the waste, and disposal of the resulting solid waste via landfills. As described in Section 5.1.3 of the Supplemental TDD, the EPA estimated costs for membrane filtration as well as solids-handling costs, which are included in the membrane filtration cost equations; the EPA assumes that plants have already installed chemical precipitation as a result of the 2020 rule limitations, and the cost methodology accounts for this treatment in place. Commenters pointed to specific plants that would incur large retrofit costs, but specific details on these costs are lacking. The EPA disagrees that allegedly "stranded" costs should be factored into its analysis. The economic achievability of a treatment technology is not based on previous or recent investments any plant has or has not made. For the 2024 rule, the EPA estimated the cost for plants to upgrade from existing requirements (the 2020 rule) to the 2024 requirements. The economic achievability of prior ELGs is evaluated specific to those ELGs. Nevertheless, the EPA ran the cumulative costs of both the 2020 rule technologies and the technologies in this final rule through IPM and found the impacts to be economically achievable. The EPA more fully addresses the concept of stranded assets, rate recovery, reliance interests, and compliance with the 2020 rule in Comment Code 5 (Regulatory Options – Compliance Cost Methodology). For more discussion of IPM results, see Section VIII.C.2 of the preamble.

One commenter questioned the EPA's cost estimates for not evaluating thermal evaporation as part of its cost analysis. As part of the final rule, the EPA did evaluate thermal evaporation as part of its cost analyses, see *FGD and CRL Thermal Evaporation Cost Methodology* memorandum (SE11694) and the response to Code 15 (FGD Wastewater - Spray Evaporation and Thermal) for more details. Another commenter expressed concern regarding an alleged loss of $4.3 million annually of revenue due to parasitic power consumption and lost heat rate from thermal treatment technology. The commenter did not provide information regarding how the loss was estimated so the EPA is unable to respond to that specific comment. The EPA does take into consideration the additional cost associated with thermal evaporation for electricity and steam (as needed) for its cost analysis, see the EPA's response to Code 15 (FGD Wastewater – Spray Evaporation and Thermal).

The EPA does not agree with commenters that an option for discharge is needed from FGD wastewater treatment systems as part of normal operations, refer to Topic *Membrane Filtration – BAT*.

FGD Byproducts

The EPA partially agrees with the commenter's assertion that "if there is a market for FGD derived from complete recycle systems, then the product is 'saleable.'" However, the ability to sell the FGD byproducts depends largely on local markets, not just whether the byproduct can be used. The EPA recognizes that it may be cost prohibitive to sell a byproduct if transportation costs overrun the profit of the sale.

The EPA disagrees with commenters that gypsum beneficial reuse would be disrupted by complying with the 2024 final rule ELGs. The commenter has not provided data supporting that cycling up chlorides in FGD scrubber operations would impact gypsum quality. Similar comments were made at the time of the 2020 rule, including that cycling up concentrations of fines could impact gypsum quality in some wet FGD systems. The EPA at the time stated that the commenters did not provide specific data on the FGD systems at plants, including gypsum quality, that would have allowed the EPA to incorporate these other factors into its estimates of flow rates, and this is still the case for this 2024 final rule. Refer to the 2020 rule comment response (EPA-HQ-OW-2009-0819-9015), Comment Code 11 (FGD Wastewater – General).

The EPA evaluates economic impacts to the industry as part of its analysis. See the RIA for a discussion of economic impacts, including revenue impacts. For fly ash sales specifically, the EPA disagrees that it has not evaluated these impacts. The EPA has updated its costs to include shifts in fly ash procurement and fly ash sales. In the cases where the EPA projected a fly ash deficit, this additional cost consistently led the least-cost methodology described in Section 5.1 of the TDD to select SDEs. The EPA's treatment costs do include transportation and disposal costs for all additional brine and lime, or other filler materials, solids generated because of the treatment of FGD wastewater; if plants need to purchase additional fly ash for encapsulation, the EPA also includes the costs associated with transporting and disposing of these solids. The costs include transporting solids to a landfill (onsite, if one exists and contains CCR, or offsite) and costs to expand onsite landfills as needed. If plants elect to not divert fly ash from sales or other marketable destinations for encapsulation, treatment of FGD wastewater using SDEs is an available alternative to achieve zero discharge. For purposes of its cost estimates, the plants selecting membrane filtration as least-cost are already transporting and disposing fly ash produced at the plant and therefore the EPA did not include an additional cost.

The EPA expects that 26 plants in the FGD wastewater population will install a membrane filtration, SDE, or thermal evaporation system because of the 2024 final rule and evaluated fly ash availability for these plants (including Winyah Generating Station, which a commenter noted was previously excluded[25]). Two plants opted into the 2020 rule voluntary incentives program (VIP), so the EPA did not evaluate fly ash availability (or FGD wastewater treatment costs) for these plants. See Topic *FGD Membrane Filtration Costs* for details on changes in fly ash availability, the amount of fly ash required, beneficial reuse, and NWQEIs.

One commenter expressed concern that there are not sufficient full-scale applications of brine encapsulation. While the EPA is not aware of full-scale installations of brine encapsulation for disposal of brine generated by membrane filtration, brine encapsulation is physico-chemically similar process to fly ash fixation which is already used by a number of facilities for their FGD wastewater. The EPA further determined that encapsulation is a viable option for FGD wastewater based on several vendors' pilot studies in various mixtures of brine, fly ash, and other constituents; refer to the *Technologies for the Treatment of Flue Gas Desulfurization Wastewater, Coal Combustion Residual Leachate, and Pond Dewatering – 2024 Final Rule* (SE11695) and the *2024 Steam Electric Supplemental Final Rule: Fly Ash Analysis* memorandum (SE11692) for additional details. The EPA included the costs of brine encapsulation in its membrane filtration technology option; however, plants may choose alternatives to brine encapsulation, such as crystallization, other thermal evaporation treatment, deep well injection, or fly ash fixation.

Commenters requested clarification on what treatment technology would constitute zero discharge and whether membrane filtration would be required. Plants may use any control technology, treatment technology, or combination of technologies to achieve compliance with the zero-discharge requirement in the final rule. Plants must ensure that no FGD wastewater is discharged; this includes commingled FGD wastewater or partially treated FGD wastewater commingled with other wastewaters that are eventually discharged. In the example noted by commenters, where FGD wastewater is treated with membrane filtration, and the permeate is sent through a reverse osmosis (RO) system, the reject from this RO system is still considered FGD wastewater. This RO reject would be prohibited from direct or indirect discharge under the final rule. Plants may dispose of the reject, from either the membrane filtration or RO in this example scenario, using various techniques. Some of these were included in the EPA's cost analysis (e.g., encapsulation, deepwell injection, and crystallizers). Plants may also use SDEs for disposal of brine. Sending the brine to a publicly owned treatment works (POTW) for treatment and discharge would be considered an indirect discharge of this wastewater. The EPA acknowledges that fly ash or gypsum conditioning may not as effectively prevent pollutants from leaching in a landfill as brine encapsulation;

[25] Although the EPA evaluated the fly ash availability for Winyah Generating Station, the EPA ultimately estimated $0 in compliance costs. The plant intends to retire all generating units by 2034 and will only need to comply with the 2020 rule requirements.

the Agency has established zero discharge limitations for CRL that will prevent the future release of these pollutants. While the Agency did not cost this practice as part of a zero-discharge option, it may be a viable and less costly option at certain facilities.

The EPA not only disagrees with the commenter that diverting fly ash to membrane brine encapsulation is an "environmental step backwards" but also finds that, due to the lower projected costs of SDEs at many facilities, the nationwide potential for diversion of fly ash is also much lower than believed at the time of the 2020 rule. Furthermore, while more CCR waste could be landfilled if a plant decided to divert fly ash from beneficial reuse, installing a zero-discharge technology would result in zero discharge of pollutant loadings from FGD wastewater. The EPA has determined that the non-water quality environmental impacts of the rule are acceptable, notwithstanding the potential that there could be some fly ash diversion at specific facilities. See the *Environmental Assessment for Final Supplemental Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category* (SE11722) for more information on the pollutant loadings for this final rule. See Section VII.B.1 of the preamble for a discussion of non-water quality environmental impacts associated with membrane filtration, SDEs, and thermal systems. Finally, the EPA disagrees with commenters that Portland cement would need to replace fly ash in concrete mixes as a result of this rulemaking and result in increased greenhouse gas emissions and other negative environmental impacts in the concrete industry; the EPA found that, even under worst-case scenarios, use of fly ash for membrane filtration brine encapsulation would not hinder the fly ash market (refer to Topic *FGD Membrane Filtration Costs* for more information).

The EPA disagrees with commenters that the effluent limitations do not reflect the performance of membrane filtration or other zero-discharge technologies, refer to Topic *Membrane Filtration – BAT* for additional information. Also see Topic *Membrane Filtration – BAT* for additional details on membrane recovery rates.

With respect to comments regarding the interaction between the CCR and ELG definition of "tank," the Agency disagrees that there should be any confusion. The EPA is adopting a final definition of "coal combustion residual surface impoundment" in 40 CFR 423.11(ee) that is the same as the definition under the CCR regulations in part 257.53. The fact that the EPA is also concurrently issuing a rule that covers additional management units (e.g., piles, inactive landfills, etc.) and inactive surface impoundments does not implicate what is or is not a surface impoundment. Furthermore, the EPA is adopting a final definition of "tank" which merely clarifies that a surface impoundment is not a tank. To the extent the commenter elects to use a technology that ends with brine encapsulation and disposal, they will have to evaluate appropriate locations for mixing of this material. Without the commenter having articulated any specific possible locations, the Agency cannot speculate but is willing to engage with the commenter if/when they ultimately seek guidance on a particular mixing location.

Refer to Topic *FGD Membrane Filtration Costs* for responses to comments on the EPA's compliance cost estimates and encapsulated brine and landfill stability. The EPA used a fly ash encapsulation recipe that is truckable; any additional costs that may be needed for a stack-out pad for drying is assumed to be captured in the contingency factor. Additionally, in general, any new landfilled material must be evaluated against the existing landfill liner and any permit conditions; this is not unique to encapsulated brine.

One commenter asserted that further research is needed on softening and its effects on treatment residuals disposal, and if the EPA were to add it to its compliance cost estimates, it would be an added capital and O&M cost. The EPA does not include softening in the membrane filtration technology option. While softening pretreatment is used for the full-scale DuPont installations due to the other components in the treatment train, the EPA does not expect that plants will need softening pretreatment for the membrane filtration (with brine encapsulation) technology option. The EPA did include costs for chemical precipitation pretreatment to remove suspended solids and scaling and foulants; refer to Topic *Pilot Studies and Installations* for more information.

with higher vulnerability potentials based upon life history traits (see Chapter 7 and Appendix I of the BCA for additional detail, U.S. EPA, 2024a).

EPA acknowledges that upstream species (such as mussels) may be exposed to toxic pollution from power plants. For example, if the host fish species to which freshwater mussels' larvae is attached during the reproduction cycle are adversely affected by toxic pollutants, it may in turn affect survival and mussels' larvae ability to move upstream. To the extent that EPA's analysis considers habitat for both fish and mussels in the receiving and downstream reaches with steam electric discharges, it implicitly accounts for potential benefits to upstream mussels' population from improved habitat of host fish species downstream. Additionally, as discussed in Chapter 3 of the BCA, EPA's modeling does not account for steam electric plant impacts on estuaries or other tidal waters for which it is not possible to model downstream transport of pollutants, but EPA recognizes that tidal flows may push waters upstream from steam electric plants and affect species residing in these waters.

EPA appreciates the comment regarding inconsistency of the T&E analysis results presented in Chapter 7 and Appendix. The Agency addressed this inconsistency in Chapter 7 of the final rule analysis. EPA notes that the apparent discrepancies the commenter raised in the list of species expected to benefit from the steam electric ELG between the 2023 proposed rule and earlier findings for the 2015 ELG Rule are due to consideration of both receiving and downstream reaches in the 2023 analysis. By contrast, the analysis for the 2015 ELG Rule had considered the effects of steam electric discharges on the receiving reaches only (see Chapter 7 of the 2015 BCA, U.S. EPA, 2015). Therefore, the analysis of this final rule (which uses the same approach as used at proposal) is more inclusive. As noted in Chapter 7 of BCA, EPA's analysis included all species currently listed or in consideration for listing under the ESA using the U.S. FWS Environmental Conservation Online System (U.S. FWS, 2020). For the final rule analysis, EPA removed several species previously included in the analysis of the 2023 proposal because they are no longer listed as threatened or endangered under the ESA, according to U.S. FWS (U.S. FWS, 2023). Although U.S. FWS recommended to downlist the Topeka shiner from "endangered" to "threatened" in the 2021 5-Year Status Review,[50] the species is still listed and therefore included in EPA's analysis.

Finally, regarding the request to provide the analyses and data used to develop the results summarized in the BCA, EPA provided these data for the final rule (see DCN SE11237), as well as the 2023 proposal (DCN SE11235) and 2015 ELG Rule (DCN SE11236).

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51. Statistics

No excerpts in Comment Code 51.

52. Numeric Limits

No excerpts in Comment Code 52.

53. General Support for/Opposition to the Rule

The EPA acknowledges that several commenters provided general statements of support or opposition to the proposed rule. To the extent the commenters did not provide specific critiques for the Agency to respond to, no further response is necessary. Where these statements summarize the more detailed

EXHIBIT 15

United States Environmental Protection Agency | Office of Water Washington, DC 20460 | EPA-821-R-24-007 April 18, 2024

Regulatory Impact Analysis for Supplemental Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category



Regulatory Impact Analysis for Supplemental Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category

EPA-821-R-24-007

April 18, 2024

U.S. Environmental Protection Agency
Office of Water (4303T)
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Abbreviations

AEO	Annual Energy Outlook
ASCC	Alaska Systems Coordinating Council
BA	Bottom ash
BAT	Best available technology economically achievable
BCA	Benefit and Cost Analysis
BEA	U.S. Bureau of Economic Analysis
BLS	U.S. Bureau of Labor Statistics
BMP	Best management practice
BPJ	Best professional judgment
BPT	Best practicable control technology currently available
BSER	Best system of emission reduction
CAA	Clean Air Act
CC	Carbon capture
CCI	Construction cost index
CCR	Coal combustion residuals
CCRMU	CCR management units
CCS	Carbon capture and storage
CEMS	Continuous emission monitoring systems
CES	Clean Energy Standards
CFR	Code of Federal Regulations
CP	Chemical precipitation
CPP	Clean Power Plan
CRL	Combustion residual leachate
CSAPR	Cross-State Air Pollution Rule
CWA	Clean Water Act
DOE	Department of Energy
EA	Environmental Assessment
ECI	Employment Cost Index
EGU	Electricity generating units
EIA	Energy Information Administration
EJ	Environmental justice
ELGs	Effluent limitations guidelines and standards
EO	Executive Order
EPA	U.S. Environmental Protection Agency
FERC	Federal Energy Regulatory Commission
FGD	Flue gas desulfurization
FOM	Fixed O&M
fPM	Filterable particulate matter
FR	Federal Register
FRCC	Florida Reliability Coordinating Council
GDP	Gross domestic product
GHG	Greenhouse gas

GW	Gigawatt
GWh	Gigawatt-hour
HICC	Hawaii Coordinating Council
HRI	Heat rate improvement
HRR	High recycle rate
HRTR	High Hydraulic Residence Time Reduction
IBR	Inverter-based resources
IPM	Integrated Planning Model
IRA	Inflation Reduction Act of 2022
ISO	Independent system operator
kWh	Kilowatt-hour
LRTR	Low Hydraulic Residence Time Reduction
MATS	Mercury and Air Toxics Standards
Mcf	Million cubic feet
MDS	Mechanical drag system
MRO	Midwest Reliability Organization
MT	Million short tons
MW	Megawatt
MWh	Megawatt-hour
NAAQS	National ambient air quality standards
NAICS	North American Industry Classification System
NERC	North American Electric Reliability Corporation
NOPP	Notice of planned participation
NPCC	Northeast Power Coordinating Council
NPDES	National Pollutant Discharge Elimination System
NPRM	Notice of proposed rulemaking
NSPS	New Source Performance Standards
NTTAA	National Technology Transfer and Advancement Act
O&M	Operation and maintenance
OMB	Office of Management and Budget
POTW	Publicly owned treatment works
PRA	Paperwork Reduction Act
PSES	Pretreatment Standards for Existing Sources
PSNS	Pretreatment Standards for New Sources
QA	Quality assurance
QC	Quality control
Quad	Quadrillion British thermal units
RCRA	Resource Recovery and Conservation Act
RIA	Regulatory Impact Analysis
RFA	Regulatory Flexibility Act
RF	Reliability First Corporation
RGGI	Regional Greenhouse Gas Initiative
RTO	Regional transmission organization
RULOF	Remaining Useful Life and Other Factors

SBA	Small Business Administration
SBREFA	Small Business Regulatory Enforcement Fairness Act
SDE	Spray dry evaporator
SERC	SERC Reliability Corporation
SISNOSE	Significant impact on a substantial number of small entities
SPP	Southwest Power Pool
TDD	Technical Development Document
TRE	Texas Reliability Entity
TWF	Toxic weighting factor
TWh	Terawatt-hour
TWPE	Toxic weighted pound equivalent
UMRA	Unfunded Mandates Reform Act
USC	Ultra-supercritical coal
VIP	Voluntary Incentive Program
VOM	Variable O&M
WECC	Western Electricity Coordinating Council
WMU	Waste management unit

3 Compliance Costs

In developing the final rule, EPA assessed the costs and economic impacts for three regulatory options summarized in Table 1-1. The options are labeled Option A through Option C in order of the stringency of the effluent limits, relative to the baseline. Key inputs for these analyses include the estimated costs to steam electric power plants (and their business, government, or non-profit owners) for implementing control technologies upon which the final BAT limitations and pretreatment standards are based,[28] and to the state and federal government for administering this rule. This chapter summarizes EPA estimates of the incremental compliance costs attributable to the regulatory options. EPA determined that state and federal governments would not incur significant incremental administrative costs.[29]

EPA applied the same methodology used to analyze the 2015 and 2020 rules, as well as the 2023 proposed rule, to calculate industry-level annualized compliance costs. See Chapter 3 of the respective RIA documents for details (U.S. EPA, 2015, 2020, 2023d). Additionally, EPA estimated that some plants incurred compliance costs for CRL treatment after the expected retirement year.

Costs associated with legacy wastewater limits under Options B and C would be incurred only as plants close and dewater their existing ponds. There is uncertainty on when plants may do so. For the purpose of this analysis, EPA anticipates that pond closures will occur on 2044 for all plants and that plants will incur initial one-time costs (*e.g.*, capital costs) in this year followed by O&M costs in the following years of the analysis (there are no incremental legacy wastewater costs under Option A).[30] Similarly, certain plants could incur costs associated with the treatment of unmanaged CRL discharged from landfills, surface impoundments, or other features in cases where a permitting authority deems, on a case-by-case basis, the discharge to be the functional equivalent of a direct discharge and requiring a permit. The costs associated with treatment of unmanaged CRL are uncertain. As a result, the Agency estimated lower- and upper-bound cost estimates for treating unmanaged CRL. These unmanaged CRL costs are added to the costs associated with CRL treatment incurred by plants. As a result, the total costs for all regulatory options as well as their estimated impacts on plants and entities are estimated using a lower and upper bound of costs.

The TDD describes the control technologies and their respective wastewater treatment performance in greater detail (U.S. EPA, 2024e). The TDD also describes how EPA estimated plant-specific capital and operation and maintenance (O&M) costs for each treatment technology, as well as for BMP plans. The cost analysis uses the 2020 rule as the baseline and incorporates technologies that plants have implemented, or would implement, to meet the 2020 ELGs, in absence of the changes in this final rule.

28 Dischargers are not required to use the technologies specified as the basis for the rule. They are free to identify other perhaps less expensive technologies as long as they meet the BAT limitations and pretreatment standards in the rule.

29 EPA estimates that the final rule will not impose significant additional administrative cost to the State and federal governments. See Section 10.7, *Paperwork Reduction Act of 1995*, for additional discussion.

30 Assuming the same 40-year surface impoundment operating life used in the 2015 CCR rule record and acknowledging that these impoundments could be anywhere in that 40-year lifespan, EPA used the midpoint of 20-years as a reasonable approximation for purposes of ensuring that these costs are included in the main cost analyses of the final rule. To the extent that costs could be incurred before this date at some plants and after this date at other plants, these nationwide costs may either over- or underestimate the site-specific costs at any particular plant.

3.1 Analysis Approach and Inputs

EPA updated estimated costs to plants for meeting the limitations of the regulatory options. There are four principal steps to compliance cost development, the last two of which are the focus of the discussion below:

1. Determining the set of plants potentially implementing compliance technologies for each regulatory option. See TDD for details (U.S. EPA, 2024e).

2. Developing plant-level costs for each wastestream and technology option. See TDD for details.

3. Estimating the year when each steam electric power plant would be required to meet new BAT effluent limits and pretreatment standards. This schedule supports analysis of the timing of compliance costs and benefits for analyses discussed in this document and in the BCA. EPA accounted for any planned unit retirements or units ceasing the combustion of coal but did estimate that some units will incur compliance costs associated with CRL treatment after retirement or ceasing the combustion of coal (see the TDD for details regarding how EPA estimated leachate flow rates for these plants).

4. Estimating *total* industry costs for all plants in the steam electric universe for each of the regulatory options.

EPA reports costs in 2023 dollars and discounts the costs to 2024.

3.1.1 Plant-Specific Costs Approach

As detailed in the TDD (U.S. EPA, 2024e), EPA developed costs for steam electric power plants to implement treatment technologies or process changes to control the wastestreams addressed by the regulatory options.

EPA assessed the operations and treatment system components currently in place at a given unit (or required to be in place to comply with other existing environmental regulations), identified equipment and process changes that plants would likely make to meet each of the regulatory options presented in Table 1-1. EPA developed costs to meet each regulatory option based on current plant equipment, processes, and treatment technologies, accounting for compliance with the 2020 rule in the baseline. Thus, the estimated costs of the regulatory options are additive to the costs of treatment technologies that plants have implemented or would implement to meet the 2020 rule. Plants that do not generate a wastestream or that employ technologies which would already meet the given limitations or standards do not incur incremental costs under the regulatory options.

In cases where several different technology options were available to meet the regulatory option limits, EPA estimated the costs of each possible option and selected the least-cost technology for each plant. For example, as detailed in the TDD, for zero-discharge systems used to meet FGD and CRL limits under

Option B and Option C, EPA generally selected the least cost option between systems using membrane filtration or spray dry evaporators (SDEs).[31]

As noted above, there is uncertainty on which plants may incur costs to meet effluent limits for unmanaged CRL as it will depend on case-by-case findings by future permitting authorities. To account for this uncertainty, EPA developed lower and upper bound scenarios that provide a range of probabilistic cost estimates based on different sets of assumptions regarding which plants may incur costs and the compliance approach. The upper bound scenario is based on probabilistically combining three sets of plant-level cost estimates using equal weights: cost estimates based on (1) each plant's closest waste management unit (WMU; either an impoundment or a landfill), (2) cases of corrective action at the WMU level, and (3) cases of corrective action where surface impoundment flows are combined at the plant level. The lower bound scenario is based on probabilistically combining plant-level costs estimates based on corrective action remedies at the WMU level or at the plant level combined with the share of remedies expected to use pumping and treating of groundwater (either alone or in combination with other remedies with groundwater collection or extraction), which make unmanaged CRL most likely to be subject to the limitations in the final rule and therefore to incur costs. Like for the upper bound scenario, EPA assumed that cost estimates were equally probable in calculating a probabilistic average plant-level cost. U.S. EPA (2024d) provides additional details on the approach used to estimate costs for unmanaged CRL treatment.

3.1.2 Plant-Level Costs

Following the approach used for the analysis of the 2015 and 2020 rules and 2023 proposal (U.S. EPA, 2015, 2020, 2023d), EPA estimated compliance costs for all existing steam electric power plants, estimated to be a total 858 plants for the point source category overall. EPA assessed that only a fraction of the universe of steam electric power plants — 232 plants — generate the wastestreams covered by the regulatory options. Furthermore, out of these plants, only a subset would incur non-zero costs under any of the scenarios analyzed for the regulatory options, based on existing control technologies. This subset of plants that incur non-zero costs varies depending on the regulatory option and cost scenario (Between 139 and 170 plants incur non-zero costs across the three regulatory options and two cost scenarios). The TDD provides additional details on this analysis.

The major components of technology costs are:

- *Capital costs* include the cost of compliance technology equipment, installation, site preparation, construction, and other upfront, non-annually recurring outlays associated with compliance with the regulatory options. EPA generally assumes that plants incur all capital costs in the year when their permit is renewed to incorporate the new limitations or standards (see *Technology Implementation Years* below). As explained in the TDD, all compliance technologies are assumed to have a useful life of 20 years.

31 One exception to this approach is CRL where EPA selected membrane filtration as the basis of the estimated compliance costs for five plants that are projected to cease operation after the period of analysis even though SDEs costs would have been lower. This resulted in the estimated total compliance costs for Option B and Option C presented in Section 3.2 being overstated by approximately $6 million (1.5 percent) on an after-tax basis.

- *Initial one-time costs* (apart from capital costs above), if applicable, include a one-time monitoring and recordkeeping cost in the first year if operation for plants operating membrane filtration system to treat FGD wastewater or CRL wastewater (see TDD for more information).

- *Annual fixed O&M costs*, if applicable, include regular *annual* monitoring. Plants incur these costs each year.

- *Annual variable O&M costs*, if applicable, include annual operating labor, maintenance labor and materials, electricity required to operate wastewater treatment systems, chemicals, combustion residual waste transport and disposal operation and maintenance, and savings from not operating and maintaining ash/FGD pond systems. Plants incur these costs each year.

In addition to these initial one-time and annual outlays, certain other costs are estimated to be incurred on a non-annual, periodic basis:

- *5-Yr fixed O&M costs*, if applicable, include remote MDS chain replacement costs that plants are estimated to incur every five years, beginning five years after the technology implementation year.

- *6-Yr fixed O&M costs*, if applicable, include mercury analyzer operations and maintenance costs that plants are estimated to incur every six years, beginning in the technology implementation year.

- *10-Yr fixed O&M costs*, if applicable, include savings from not needing to periodically maintain ash/FGD pond systems. Plants are estimated to incur savings every 10 years from not needing to purchase earthmoving equipment for the pond systems, beginning 5 years after the technology implementation year.

Based on information in the record concerning the normal downtime of electricity generating units, EPA estimated that plants would be able to coordinate the implementation of wastewater treatment systems during already scheduled downtime.

3.1.3 Technology Implementation Years

The years in which individual steam electric power plants are estimated to implement control technologies are an important input to the time profile of costs that plants would incur due to the regulatory options. This profile is used to estimate the annualized costs to the steam electric industry and society associated with the regulatory options.

EPA envisions that each plant to which the regulatory options would apply would study available technologies and operational measures, and subsequently install, incorporate, and optimize the technology most appropriate for each site. As part of its consideration of the technological availability and economic achievability of the BAT limitations and pretreatment standards in the rule and following the approach the Agency used for the 2015 and 2020 rules as well as the 2023 proposal, EPA considered the magnitude and complexity of process changes and new equipment installations that would be required at plants to meet the requirements of the regulatory options in determining the time plant owners may need to comply with any revised limitations or pretreatment standards. See discussion in the TDD (U.S. EPA, 2024e).

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As described in greater detail in the NPRM, EPA is establishing availability timing for BAT limitations that is "as soon as possible" after the effective date of any final rule but "no later than" five years from the effective date (*i.e.*, a 2029 deadline).[32]

The timing decision represents when the technologies are available, accounting for the need to provide sufficient time for plant owners to raise capital, plan and design systems, procure equipment, and construct and then test systems. EPA also considered the time frames needed for appropriate consideration of any plant changes being made in response to other agency rules affecting the steam electric power generating industry. Specifying compliance deadlines in the future enables plants to take advantage of planned shutdown or maintenance periods to install new pollution control technologies. This allows for the coordination of generating unit outages in order to maintain grid reliability and prevent any potential impacts on electricity availability caused by forced outages. It is not possible to predict, for each plant, exactly the date the final rule will be incorporated into permits, for purposes of determining exactly when plants will incur costs to meet the new requirements. Similar to the approach used in analyzing the 2015, 2020, and proposed 2023 rules, EPA generally expects plants to meet the new BAT limitations and pretreatment standards in a somewhat staggered fashion, given that (1) the permitting authority determines the date after considering certain specified factors, and (2) all permits are not re-issued at the same time due to their 5-year permit term. Thus, for the cost and economic impact analyses, EPA assumed implementation over a 5-year period preceding the established "no later than" date.[33, 34]

Costs associated with legacy wastewater limits under Options B and C would be incurred only as plants close and dewater their existing ponds. Given the uncertainty on when plants may do so, for the purpose of this analysis EPA assumed that any pond closures would occur after 2044 and further assumed that costs to comply with the limits would be incurred starting in that year.

Similarly, certain plants could incur costs associated with the treatment of unmanaged CRL discharged from landfills, surface impoundments, or other features in cases where a permitting authority deems, on a case-by-case basis, the discharge to be the functional equivalent of a direct discharge and requiring a permit. Because these discharges are uncertain, EPA assumed plants would incur costs associated with treating unmanaged CRL at the same time as other wastewater treatment technologies.

For the purpose of this analysis, EPA accounted for the timing of announced unit retirements or repowerings in determining the compliance year for the plant. Specifically, in cases where the announced retirement occurs after the default compliance year based on the permit renewal cycle but before the rule compliance deadline, EPA assumed that permit authorities would set the "no later than" compliance date

32 EPA did not estimate costs over different timeframes for indirect dischargers. The CWA mandates that such dischargers meet applicable standards three years from promulgation of final PSES. This timing is consistent with the modeling approach during Period 1 as described in the BCA.

33 For the purpose of the analysis, EPA assigned an estimated compliance year to each of the 232 steam electric power plants analyzed for the final rule based on each plant's estimated NPDES permit renewal year and, similar to the approach used for the 2015 and 2020 rules and 2023 proposal, the assumption that all permits will be renewed promptly (no administrative continuances). EPA projected future NPDES permit years by assuming permits are renewed every 5 years, *i.e.*, a permit expiring in 2023 would be renewed in 2028 and 2033.

34 EPA initially estimated a compliance year for each plant based on a compliance deadline of 2030. During the analyses, EPA subsequently revised the deadline to 2029 and revised plant-specific compliance years by subtracting one year for each plant rather than re-estimating compliance years only for those plants whose compliance year did not meet the deadline.

to correspond to the retirement date. In these cases, the plant would incur no incremental costs to comply with the final rule.

EPA also accounted for announced unit retirements or repowerings in the social cost analysis, which is discussed and detailed in Chapter 12 of the BCA. Specifically, EPA assumed zero O&M costs for BA transport water and FGD wastewater treatment in all years following a unit's retirement or repowering, but continued O&M costs for CRL since treatment of the CRL wastewater is expected to continue even after a unit ceases to generate electricity.

3.1.4 Total Compliance Costs

EPA used the following methodology and assumptions to aggregate compliance cost components, described in the preceding sections, and develop total plant compliance costs for regulatory options A through C:

- EPA estimated compliance costs (including zero costs) for each of the 232 steam electric power plants with the relevant wastestreams, *i.e.*, coal-fired power plants (see TDD for details). All other plants covered by the steam electric power point source category do not generate wastestreams covered by the regulatory options and therefore incur zero costs.

- EPA restated compliance costs estimated in the preceding step, accounting for the specific years in which each plant is assumed to undertake compliance-related activities and in 2023 dollars, using the Construction Cost Index (CCI) from McGraw Hill Construction (2023), the Employment Cost Index (ECI) published by the Bureau of Labor Statistics (BLS) (2023), and the Gross Domestic Product (GDP) deflator index published by the U.S. Bureau of Economic Analysis (BEA) (2023).[35]

- EPA discounted all cost values to 2024, using a rate of 3.76 percent.[36]

35 Specifically, EPA brought all compliance costs to an estimated technology implementation year using the CCI from McGraw Hill Construction (McGraw Hill Construction Engineering News-Record. (2023). *Construction Cost Index (CCI)*) or the ECI from the Bureau of Labor Statistics (U.S. Department of Labor. Bureau of Labor Statistics. (2023). *Total compensation for All Civilian workers in All industries and occupations, Index*), depending on the cost component. The Agency used the average of the year-to-year changes in the CCI (or ECI) over the most recent ten-year reporting period to bring these values to an estimated compliance year. Because the CCI (or ECI) is a nominal cost adjustment index, the resulting technology cost values are as of the compliance year and in the dollars of the technology implementation year. To restate compliance cost values in 2023 dollars, the Agency deflated the nominal dollar values to 2023 using the average of the year-to-year changes in the GDP deflator index published by the BEA over the most recent ten-year reporting period. As a result, all dollar values reported in this analysis are in constant dollars of the year 2023.

36 Compliance costs are discounted and annualized using a rate of 3.76 percent, which is the estimated weighted average cost of capital for the power sector (see U.S. Environmental Protection Agency. (2023a). *Documentation for EPA's Power Sector Modeling Platform v6 Using the Integrated Planning Model Post-IRA 2022 Reference Case*. Retrieved from **https://www.epa.gov/system/files/documents/2023-03/EPA%20Platform%20v6%20Post-IRA%202022%20Reference%20Case.pdf** for details). This rate differs from the social discount rate of 2 percent used when presenting the social costs and benefits in the BCA, following OMB guidance in Circular A-4 (U.S. Office of Management and Budget. (2023). *Circular A-4: Regulatory Analysis*. Retrieved from https://www.whitehouse.gov/wp-content/uploads/2023/11/CircularA-4.pdf).

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- EPA annualized one-time costs and costs recurring on other than an annual basis over a specific useful life, implementation, and/or event recurrence period, using a rate of 3.76 percent: [37]
  - Capital costs of each compliance technology: 20 years
  - Initial one-time costs: 20 years[38]
  - 5-Yr O&M: 5 years
  - 6-Yr O&M: 6 years
  - 10-Yr O&M: 10 years
- EPA added annualized capital, initial one-time costs, and annualized O&M costs recurring on other than an annual basis to the annual O&M costs to derive total annualized compliance costs.

EPA accounted for the timing of announced plant retirements in determining the useful life over which to annualize recurring costs. In cases where a plant's announced retirement year occurs after the first instance of a recurring O&M cost for BA transport water and FGD wastewater treatment but before the second instance, EPA adjusted the useful life of that cost category to be the number of years that the plant is expected to operate after the first instance.

EPA did not adjust the annualization of capital costs to reflect plant-specific considerations. EPA annualized capital costs over 20 years but recognizes that some plants may retire units sooner than the 20-year life of the equipment. EPA determined the 20-year annualization period to be reasonable for this analysis because some regulators may allow utilities to recover the value of undepreciated assets in their rate base on a case-by-case basis.[39]

For the assessment of compliance costs to steam electric power plants, EPA considered costs on both a pre-tax and after-tax basis. Pre-tax costs provide insight on the total expenditures as initially incurred by the plants. After-tax costs are a more meaningful measure of compliance impact on privately owned for-profit plants, and incorporate approximate capital depreciation and other relevant tax treatments in the analysis. EPA calculated the after-tax value of compliance costs by applying combined federal and State tax rates to the pre-tax cost values for privately owned for-profit plants.[40] For this adjustment, EPA used State corporate rates from the Federation of Tax Administrators (2023) combined with a 21 percent federal corporate tax rate. As discussed in the relevant sections of this document, EPA uses either pre- or after-tax compliance costs in different analyses, depending on the concept appropriate to each analysis

37 U.S. Environmental Protection Agency. (2023d). *Regulatory Impact Analysis for Proposed Supplemental Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category*. (EPA-821-R-23-002).

38 EPA annualized these non-equipment outlays over 20 years to match the estimated performance life of compliance technology components.

39 EPA received public comments on the 2023 proposed rule confirming that a typical depreciation and amortization period is 20+ years. One commenter stated that "typical amortization periods for investments" on the scale of the 2020 Final Rule are 20 years (EPA-HQ-OW-2009-0819-10079). Another commenter described the rate recovery request of a utility to comply with the 2020 Final Rule with a proposed 20-year depreciation and amortization period, though noted that depreciation periods for equipment could be as long as 50 or 60 years (EPA-HQ-OW-2009-0819-10161).

40 Government-owned entities and cooperatives are not subject to income taxes. To distinguish among the government-owned, privately owned, and cooperative ownership categories, EPA relied on the Steam Electric Survey and additional research on parent entities using publicly available information. See *Chapter 4: Cost and Economic Impact Screening Analyses* for further discussion of these determinations.

(*e.g.*, cost-to-revenue screening-level analyses are conducted using after-tax compliance costs). Note that for social costs, which are discussed and detailed in Chapter 12 of the BCA, EPA uses pre-tax costs.[41]

3.1.5 Voluntary Incentive Program

As described in the 2020 rule and 2023 proposed rule, under the voluntary incentive program (VIP), plants that discharge directly to waters can voluntarily commit to meeting more stringent FGD limitations based on a membrane filtration treatment technology instead of limits based on CP+LRTR technology. VIP participants had more time – until 2028 – to meet the lower limits based on membrane filtration, as compared to having to meet the limits based on CP+LRTR by 2025. Plants identified as participating in the VIP program in the baseline (*i.e.*, to comply with the 2020 rule) incur zero FGD wastewater treatment costs in this final rule.

3.2 Key Findings for Regulatory Options

3.2.1 Estimated Industry-level Total Compliance Costs

Table 3-1 and Table 3-2 present lower and upper bound compliance cost estimates for the regulatory options.[42]

Table 3-1: Estimated Total Annualized Compliance Costs (in millions, 2023$, at 2024) – Lower Bound

Regulatory Option	Pre-Tax Compliance Costs				After-Tax Compliance Costs			
	Capital Technology	Other Initial One-Time	Total O&M	Total	Capital Technology	Other Initial One-Time	Total O&M	Total
Option A	$232	$0.1	$247	$479	$186	$0.1	$200	$386
Option B	$284	$0.2	$312	$596	$229	$0.1	$250	$479
Option C	$336	$0.2	$359	$695	$270	$0.2	$286	$557

Source: U.S. EPA Analysis, 2024.

41 As described in Chapter 12 of the BCA, EPA used costs incurred by steam electric power plants for the labor, equipment, material, and other economic resources needed to comply with the regulatory options as a proxy for social costs. The social cost analysis considers costs on an as-incurred, year-by-year basis. In the social cost analysis, EPA assumed that the market prices for labor, equipment, material, and other compliance resources represent the opportunity costs to society for use of those resources in regulatory compliance. EPA further assumed that the regulatory options do not affect the aggregate quantity of electricity that would be sold to consumers and, thus, that the rule's social cost would include no changes in consumer and producer surplus *from changes in electricity sales* by the electricity industry in aggregate. Given the small impact of the regulatory options on electricity production cost for the total industry (see *Chapter 5*), this is a reasonable assumption.

42 As discussed in Section 3.1.1 (see footnote 31), EPA did not select the lowest-cost technology for five plants to meet zero-discharge limits for CRL. This resulted in the estimated total compliance costs for Option B and Option C presented in this section being overstated by approximately $6 million (1.5 percent of total costs) on an after-tax basis.

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Table 3-2: Estimated Total Annualized Compliance Costs (in millions, 2023$, at 2024) – Upper Bound

Regulatory Option	Pre-Tax Compliance Costs				After-Tax Compliance Costs			
	Capital Technology	Other Initial One-Time	Total O&M	Total	Capital Technology	Other Initial One-Time	Total O&M	Total
Option A	$453	$0.1	$595	$1,048	$372	$0.1	$490	$863
Option B	$505	$0.2	$659	$1,164	$415	$0.1	$541	$956
Option C	$557	$0.2	$706	$1,263	$456	$0.2	$577	$1,033

Source: U.S. EPA Analysis, 2024.

Table 3-3 and Table 3-4 show the breakout of total upper and lower bound compliance costs for each option by wastestream.[43]

Table 3-3: Estimated Total Annualized Compliance Costs, by Wastestream (in millions, 2023$, at 2024) – Lower Bound

Regulatory Option	Pre-Tax Compliance Costs					After-Tax Compliance Costs				
	BA Transport Water	FGD Wastewater	CRL	Legacy	Net Total Costs	BA Transport Water	FGD Wastewater	CRL	Legacy	Net Total Costs
Option A	$19	$179	$281	$0	$479	$15	$139	$232	$0	$386
Option B	$19	$179	$370	$28	$596	$15	$139	$302	$23	$479
Option C	$30	$205	$433	$28	$695	$23	$160	$350	$23	$557

Source: U.S. EPA Analysis, 2024.

Table 3-4: Estimated Total Annualized Compliance Costs, by Wastestream (in millions, 2023$, at 2024) – Upper Bound

Regulatory Option	Pre-Tax Compliance Costs					After-Tax Compliance Costs				
	BA Transport Water	FGD Wastewater	CRL	Legacy	Net Total Costs	BA Transport Water	FGD Wastewater	CRL	Legacy	Net Total Costs
Option A	$19	$179	$849	$0	$1,048	$15	$139	$709	$0	$863
Option B	$19	$179	$939	$28	$1,164	$15	$139	$778	$23	$956
Option C	$30	$205	$1,001	$28	$1,263	$23	$160	$826	$23	$1,033

Source: U.S. EPA Analysis, 2024.

3.2.2 Estimated Regional Distribution of Incremental Compliance Costs

Table 3-5 and Table 3-6 report the estimated lower and upper bound annualized total costs for each regulatory option at the level of a North American Electric Reliability Corporation (NERC) region.[44] As

43 One retired plant incurs legacy costs in the analysis. These costs are reflected in the total cost values in tables in Section 3.2. The costs for this plant are not incorporated in the rest of the RIA analyses because the plant does not have generation revenue or ratepayers.

44 No steam electric power plant is estimated to incur compliance costs in the ASCC and HICC NERC regions and these two regions are therefore omitted from the presentation of results.

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explained in Chapter 2 (Overview of the Steam Electric Industry), because of differences in operating characteristics of steam electric power plants across NERC regions, as well as differences in the economic and electric power system regulatory circumstances of the NERC regions themselves, the regulatory options may affect costs, profitability, electricity prices, and other impact measures differently across NERC regions.

Table 3-5: Estimated Annualized Total Compliance Costs by NERC Region (in millions, 2023$, at 2024) – Lower Bound

NERC Region[a]	Pre-Tax Incremental Compliance Costs				After-Tax Incremental Compliance Costs			
	Capital Technology	Other Initial One-Time	Total O&M	Total	Capital Technology	Other Initial One-Time	Total O&M	Total
Option A								
MRO	$29.1	$0.0	$24.9	$54.0	$23.6	$0.0	$20.1	$43.7
NPCC	$3.0	$0.0	$3.0	$6.0	$2.2	$0.0	$2.2	$4.4
RF	$70.3	$0.0	$76.0	$146.3	$54.3	$0.0	$58.7	$113.0
SERC	$111.4	$0.0	$116.7	$228.2	$91.6	$0.0	$97.4	$189.0
TRE	$4.1	$0.0	$3.8	$7.9	$3.6	$0.0	$3.2	$6.8
WECC	$13.5	$0.0	$22.7	$36.2	$10.6	$0.0	$17.9	$28.5
Total	**$231.7**	**$0.1**	**$247.5**	**$479.2**	**$186.1**	**$0.1**	**$199.8**	**$386.0**
Option B								
MRO	$39.5	$0.0	$30.3	$69.8	$32.4	$0.0	$24.3	$56.7
NPCC	$3.3	$0.0	$2.9	$6.1	$2.4	$0.0	$2.1	$4.5
RF	$89.6	$0.1	$118.4	$208.0	$69.0	$0.1	$90.3	$159.3
SERC	$129.3	$0.1	$128.3	$257.7	$106.7	$0.0	$106.9	$213.6
TRE	$5.1	$0.0	$4.1	$9.2	$4.3	$0.0	$3.5	$7.8
WECC	$17.1	$0.0	$27.4	$44.5	$14.0	$0.0	$22.4	$36.5
Total	**$284.1**	**$0.2**	**$311.7**	**$596.0**	**$229.0**	**$0.1**	**$249.8**	**$479.0**
Option C								
MRO	$44.2	$0.0	$32.8	$77.0	$35.8	$0.0	$26.1	$61.9
NPCC	$3.3	$0.0	$2.9	$6.1	$2.4	$0.0	$2.1	$4.5
RF	$103.2	$0.1	$132.0	$235.3	$79.0	$0.1	$100.3	$179.3
SERC	$156.2	$0.1	$150.1	$306.4	$129.1	$0.1	$124.5	$253.6
TRE	$7.7	$0.0	$6.4	$14.1	$6.5	$0.0	$5.4	$11.9
WECC	$21.2	$0.0	$34.4	$55.6	$17.1	$0.0	$27.7	$44.8
Total	**$335.9**	**$0.2**	**$358.9**	**$695.0**	**$270.1**	**$0.2**	**$286.4**	**$556.6**

a. EPA estimated zero ELG compliance costs in the ASCC and HICC regions. These two regions are omitted from the table presentation. This omission does not affect totals.

Source: U.S. EPA Analysis, 2024.

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Table 3-6: Estimated Annualized Total Compliance Costs by NERC Region (in millions, 2023$, at 2024) – Upper Bound

NERC Region[a]	Pre-Tax Incremental Compliance Costs				After-Tax Incremental Compliance Costs			
	Capital Technology	Other Initial One-Time	Total O&M	Total	Capital Technology	Other Initial One-Time	Total O&M	Total
Option A								
MRO	$54.8	$0.0	$63.3	$118.2	$43.2	$0.0	$48.6	$91.9
NPCC	$3.2	$0.0	$3.2	$6.4	$2.3	$0.0	$2.3	$4.7
RF	$109.9	$0.0	$135.2	$245.2	$86.4	$0.0	$106.9	$193.3
SERC	$225.3	$0.0	$292.7	$518.1	$192.1	$0.0	$252.3	$444.4
TRE	$8.4	$0.0	$8.3	$16.8	$7.3	$0.0	$7.2	$14.6
WECC	$49.8	$0.0	$90.9	$140.7	$39.4	$0.0	$71.8	$111.3
Total	**$452.6**	**$0.1**	**$595.0**	**$1,047.7**	**$372.0**	**$0.1**	**$490.5**	**$862.6**
Option B								
MRO	$65.3	$0.0	$68.7	$134.0	$52.0	$0.0	$52.8	$104.9
NPCC	$3.5	$0.0	$3.0	$6.5	$2.6	$0.0	$2.2	$4.8
RF	$129.2	$0.1	$177.6	$306.9	$101.1	$0.1	$138.5	$239.6
SERC	$243.2	$0.1	$304.3	$547.6	$207.2	$0.0	$261.9	$469.1
TRE	$9.4	$0.0	$8.7	$18.0	$8.1	$0.0	$7.5	$15.6
WECC	$53.4	$0.0	$95.6	$149.0	$42.9	$0.0	$76.4	$119.2
Total	**$505.1**	**$0.2**	**$659.2**	**$1,164.4**	**$414.9**	**$0.1**	**$540.5**	**$955.6**
Option C								
MRO	$69.9	$0.0	$71.2	$141.1	$55.4	$0.0	$54.6	$110.1
NPCC	$3.5	$0.0	$3.0	$6.5	$2.6	$0.0	$2.2	$4.8
RF	$142.8	$0.1	$191.3	$334.2	$111.0	$0.1	$148.5	$259.6
SERC	$270.0	$0.1	$326.1	$596.2	$229.6	$0.1	$279.5	$509.1
TRE	$12.0	$0.0	$11.0	$23.0	$10.3	$0.0	$9.4	$19.7
WECC	$57.5	$0.0	$102.5	$160.0	$46.0	$0.0	$81.6	$127.5
Total	**$556.9**	**$0.2**	**$706.4**	**$1,263.5**	**$456.0**	**$0.2**	**$577.1**	**$1,033.3**

a. EPA estimated zero ELG compliance costs in the ASCC and HICC regions. These two regions are omitted from the table presentation. This omission does not affect totals.

Source: U.S. EPA Analysis, 2024.

3.2.3 Key Uncertainties and Limitations

Economic analyses are not perfect predictions and thus, like all such analyses, this analysis has some uncertainties and limitations.

- The compliance costs used in this analysis for the regulatory options reflect unit retirements, conversions, and repowerings that have occurred or have been announced and are scheduled to occur by the end of 2029. For details, see TDD (U.S. EPA, 2024e). To the extent that actual unit retirements, conversions, and repowerings at steam electric power plants differ from announced changes, estimated annualized compliance costs of the regulatory options may differ from actual costs.

- EPA assumed that the equipment installed to meet any new limitations could reasonably be estimated to operate for 20 years or more, based on a review of reported performance characteristics of the equipment components. EPA also determined the 20-year annualization

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period to be reasonable for this analysis because some regulators may allow utilities to recover the value of undepreciated assets in their rate base on a case-by-case basis. EPA thus used 20 years as the basis for the cost and economic impact analyses that account for the estimated operating life of compliance technology. To the extent that the actual service life is longer or shorter than 20 years, costs presented on annual equivalent basis would be over- or under-stated. This includes cases where a plant upgrades treatment technologies to comply with the ELGs but ceases operating before the 20-year life of the equipment.

- Annualized compliance costs depend on the assumed technology implementation year. For the purpose of the cost and economic impact analyses, EPA determined years in which technology implementation would reasonably be estimated to occur across the universe of steam electric power plants, based on plant-specific information about existing NPDES permits and extrapolating future permit issuance dates assuming permits are renewed every five years. To the extent that compliance costs are incurred in an earlier or later year, the annualized values presented in this section may under or overstate the annualized total costs of the regulatory options.

- Plants may incur compliance costs associated with meeting legacy wastewater limits when they close and dewater their existing ponds. As there are no requirements for the ponds to be closed, there is uncertainty on whether and when operators may incur such costs. EPA assumed that pond closures will occur in 2044 at which time plants would incur initial one-time costs associated with treatment of legacy wastewater. As a result, this analysis may under or overstate compliance costs in cases where plants choose to close their ponds before or after 2044.

- Plants may incur compliance costs to comply with unmanaged CRL discharged from landfills, surface impoundments, or other features in cases where a permitting authority deems, on a case-by-case basis, the discharge to be the functional equivalent of a direct discharge and requiring a permit. Because these discharges are uncertain, EPA developed lower and upper bound analyses scenarios that rely on probabilistic estimates of plants that may be subject to the limits, compliance approach, and associated costs. See Section 3.1.1 for a description of these scenarios. Additionally, EPA assumed plants would incur these costs at the same time as they would incur costs associated with other treatment technologies. This may under or overstate the costs of unmanaged CRL treatment if plants incur these costs before or after the assumed compliance year in the analysis.

3.3 Costs to New Sources

Electric power generating plants that meet the definition of a "new source" will be required to achieve the final NSPS, in the case of direct dischargers, or Pretreatment Standards for New Sources (PSNS), in the case of indirect dischargers. This section summarizes the data and methodology used to estimate compliance costs for new steam electric power plants (for a more detailed description of the methodology, see TDD, U.S. EPA, 2024e). The section also assesses the relative magnitude of the compliance costs by comparing them to the costs of new coal steam generation. EPA's final rule is based on the suite of technologies identified for Option B. EPA's approach to assess costs to new sources and the potential barrier to entry for new plants is based on the same methodology used for the 2015 rule (U.S. EPA, 2015).

3.3.1 Analysis Approach and Inputs

EPA developed compliance costs for new plants using a methodology similar to the one used to develop compliance costs for existing plants (see TDD for details). EPA did not have information about which entities will construct new plants, the exact characteristics of such plants, or the timing of new plant construction. As a result, EPA calculated and analyzed compliance costs for a hypothetical plant. The Agency treated the incurrence of costs in this analysis as though new plants would be constructed, and additional wastewater treatment costs incurred, as of the rule promulgation, (*i.e.*, 2024). This is a conservative assumption since new sources would not incur costs until there is an NPDES permit applying the NSPS to them.

Compliance costs for new plants under the final NSPS (Option B) include capital costs, initial one-time costs, and annual O&M costs. EPA made the same adjustments to the plant-specific costs for new plants described in the TDD, as those made to develop total compliance costs for existing plants:

- First, EPA brought all compliance costs to 2024 using CCI (or ECI) and restated in 2023 dollars using GDP Deflator.
- EPA then annualized each non-annual cost component over the expected useful life of the technology/processes it represents (capital cost and initial one-time costs over 20 years) using 3.76 percent as the assumed cost of capital.
- Finally, EPA added these annualized capital, initial one-time, and O&M costs.

Table 3-7 presents estimated new plant compliance costs under the final rule (Option B) for new sources. The Agency estimated costs for a new 650 MW coal-fired steam electric power plant. Per MW, EPA estimated that a new plant will cost $4,916 per MW. For more details on the methodology used to estimate compliance costs for new plants, see the TDD (U.S. EPA, 2024e).

Table 3-7: Annualized Pre-tax Compliance Costs for a Hypothetical New 650 MW Plant Under Final Rule (2023$, at 2024)

Total Costs				Costs per MW[a]			
Capital Costs	Non-Fuel O&M Costs	One-Time Costs	Total Annualized Costs	Capital Costs	Non-Fuel O&M Costs	One-Time Costs	Total Annualized Costs
$1,482,503	$1,701,998	$11,088	$3,195,589	$2,281	$2,618	$17	$4,916

a. Unit costs are based on capacity of 650 MW.

Source: U.S. EPA analysis, 2024.

3.3.2 Key Findings for Regulatory Options

EPA assessed the effects of the final NSPS requirements under the final rule for new plants by comparing the compliance costs for new plants to the overall cost of *building and operating* new plants, on a per

MW basis. This analysis assesses the requirements and costs imposed on new plants in relation to the costs that would be incurred for building and operating new plant *without the new plant requirements.*[45]

To assess the relative magnitude of compliance costs for new plants, EPA compared the pre-tax costs presented in Section 3.2.1, to the total cost of building and operating a new plant, also on a pre-tax and per MW basis. EPA obtained the overnight capital[46] and O&M costs of building and operating a new plant from EIA (2024). These costs are based on a new ultra-supercritical coal (USC) plant with no carbon capture (CC) technology with a total generation capacity of 650 MW (EIA, 2024). EPA compared the ELG cost estimates for the 650 MW plant presented in Table 3-7 to the costs of a new USC plant without CC.

EPA also estimated annual fuel O&M costs for operating the plant based on an assumed capacity factor of 90 percent, annual heat rate of a new USC without CC from EIA (2024), and weighted average cost of coal delivered to the power sector from EIA (2023h). EPA annualized new USC without CC plant building and operating costs over 40 years using a discount rate of 3.76 percent.[47] EPA then compared the estimated compliance costs for new plants to the costs of constructing and operating new coal steam capacity. Table 3-8 presents the results of this comparison. The Agency estimated that compliance costs for adding treatment technology at a new plant would represent 1.1 percent of the total annualized costs of building and operating a new plant.

Table 3-8: One-Time & O&M costs for a Hypothetical New 650 MW Plant Under Final Rule

Cost Component	Annualized Costs of New Coal-fired Generation (2023$/MW)	Compliance Costs (2023$/MW)	% of New Generation Cost
Capital	$199,936	$2,281	1.1%
Non-Fuel Annual O&M[a]	$112,095	$2,618	1.0%
Fuel Annual O&M	$153,535		
Total Annualized Costs[b]	$465,566	$4,916	1.1%

a. Fuel costs were estimated assuming heat rate of 8,638 Btu/kWh (EIA, 2024) and the cost of coal delivered to the power sector of 2.25 2023$/MMbtu (EIA (2023h) weighted average cost for all coal ranks in 2022 dollars, converted to 2023 dollars using GDP deflator).

b. Includes annualized initial one-time costs.

Source: EIA, 2024; U.S. EPA analysis, 2024.

45 Note that the market analyses described in Chapter 5 also incorporate costs to new sources as part of inputs to the Integrated Planning Model (IPM). This analysis tests the impact of the new plant requirements in electricity markets accounting for the expected number and timing of new plant installations, and provides additional insight on whether the costs of meeting the standards specified by the final NSPS and PSNS would affect future capacity additions. Since IPM projects no new coal-fired generating plant in the Base Case, however, the market analysis does not offer additional insight on the impacts of the NSPS compliance costs on new generating capacity.

46 Overnight capital costs includes labor and material costs due to installation, mechanical equipment and labor, electrical instrumentation, and indirect management costs according to U.S. Energy Information Administration. (2024). *Capital Cost and Performance Characteristics for Utility-Scale Electric Power Generating Technologies.* Retrieved from https://www.eia.gov/analysis/studies/powerplants/capitalcost/pdf/capital_cost_AEO2025.pdf.

47 The Agency annualized capital costs for a new USC coal unit without CC based on the predicted performance life reported in ibid..

3.3.3 Key Uncertainties and Limitations

Despite EPA's use of the best available information and data available, including information provided to EPA in the industry survey, this analysis has uncertainties and limitations.

- EPA notes that no new coal capacity additions are projected between 2024 and 2050 in AEO2023 (EIA, 2023b), making the assessment of the relative costs and of any barrier the final ELGs may pose to additional generation hypothetical. Similarly, results of the electricity market model using IPM (Chapter 5) shows no additional coal steam capacity being built through 2050 in the Base Case (in the absence of the ELGs) or in the policy case (with the ELGs), and do not offer a basis for determining, using IPM, whether the ELGs present a cost barrier to new coal generation. However, as discussed in Chapter 5, the IPM results demonstrate that the ELGs do not pose a barrier to new electricity generation overall; the model shows increases new capacity projected in IPM under the final rule option.

- Second, EPA made assumptions about plant characteristics in the absence of the final rule. These assumptions affect the types of wastestreams that a plant would generate and changes needed to meet the final limitations and standards. To the extent that the characteristics of new plants differ from EPA's assumed characteristics, the costs may be under or overstated.

- Finally, the costs of implementing and operating compliance technology vary based on the size of the generating plant and plant configuration. To the extent that the size and configuration of a potential new coal plant is different from assumptions that underlay new capacity costs, the relative magnitude of the compliance costs for new steam electric capacity may be under- or over-estimated. For instance, EPA used data from EIA on the cost of additional capacity based on a new 650 MW USC without CC plant (EIA, 2024). The cost of building new capacity for a smaller or larger plant may be smaller or larger on a per MW basis than those of a 650 MW plant.

4 Cost and Economic Impact Screening Analyses

4.1 Analysis Overview

Following the same methodology used for the 2015, 2020 and proposed 2023 rule analyses (U.S. EPA, 2015, 2020, 2023d), EPA assessed the costs and economic impacts of the regulatory options in two ways:

1. A screening-level assessment reflecting current operating characteristics of steam electric power plants and with assignment of estimated compliance costs to those plants. This analysis assumes no changes in operating characteristics — *e.g.*, quantity of generated electricity and revenue — as a result of the regulatory options. This screening-level assessment, which is documented in this chapter, includes two specific analyses:
   - A cost-to-revenue screening analysis to assess the impact of compliance outlays on individual steam electric power plants (Section 4.2)
   - A cost-to-revenue screening analysis to assess the impact of compliance outlays on domestic parent-entities owning steam electric power plants (Section 4.3)
2. A broader electricity market-level analysis based on IPM (the Market Model Analysis). This analysis, which provides a more comprehensive indication of the economic achievability of the final rule, including an assessment of incremental plant closures (or avoided closures), is discussed in Chapter 5. Unlike the preceding analysis discussed in this chapter, the Market Model Analysis accounts for estimated changes in the operating characteristics of plants from both estimated changes in electricity markets and operating characteristics of plants independent of, and as a result of, the regulatory options.

4.2 Cost-to-Revenue Analysis: Plant-Level Screening Analysis

The cost-to-revenue measure compares the cost of implementing and operating compliance technologies with the plant's operating revenue and provides a screening-level assessment of the impact that might be estimated of the regulatory options. As discussed in U.S. EPA (2015; see Chapter 2), the majority of steam electric power plants operate in states with regulated electricity markets. EPA estimates that plants located in these states may be able to recover compliance cost-based increases in their production costs through increased electricity prices, depending on the business operation model of the plant owner(s), the ownership and operating structure of the plant itself, and the role of market mechanisms used to sell electricity. In contrast, in states in which electric power generation has been deregulated, cost recovery is not guaranteed. While plants operating within deregulated electricity markets *may be* able to recover some of their additional production costs through increased revenue, it is not possible to determine the extent of cost recovery ability for each plant.[48]

In assessing the cost impact of the regulatory options on steam electric power plants in this screening-level analysis, the Agency assumed that the plants would not be able to pass any of the change in their

48 While the regulatory status in a given state affects the ability of electric power plants and their parent entities to recover electricity generation costs, it is not the only factor and should not be used solely as the basis for cost-pass-through determination.

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production costs to consumers (zero cost pass-through). This assumption is used for analytic convenience and provides a *worst-case* scenario of regulatory impacts to steam electric power plants.[49]

4.2.1 Analysis Approach and Data Inputs

As described in Chapter 1, EPA estimates all steam electric power plants to meet any new requirements for bottom ash transport water, FGD wastewater, and CRL between 2026 and 2030. The Agency used the same approach from the 2015 rule, 2020 rule, and 2023 proposed rule to conduct the analysis of the final rule's regulatory options A through C.

EPA updated the approach used for the 2015 and 2020 rules and 2023 proposal to incorporate more recent data. For the current analysis, EPA used 2024 as the basis for comparing after-tax compliance costs (see Chapter 3) to revenue at the plant level.[50] For this comparison, EPA developed plant-level revenue values for all steam electric power plants using data from the Department of Energy's Energy Information Administration (EIA) on electricity generation by prime mover, and utility/operator-level electricity prices and disposition. Specifically, EPA multiplied the 6-year average of electricity generation values over the period 2016 to 2021 from the EIA-923 database by 6-year average electricity prices over the period 2016 to 2021 from the EIA-861 database (EIA, 2022a, 2022d).[51, 52] EPA estimated compliance costs in 2023 dollars. To provide cost and revenue comparisons on a consistent analysis-year (2024) and dollar-year (2023) basis, EPA adjusted the EIA electricity price data, which are reported in nominal dollars of each year.

Cost-to-revenue ratios are used to describe impacts to entities because they provide screening-level indicators of potential economic impacts. Just as for the plants owned by small entities under guidance in U.S. EPA (2006), and the approach EPA has used previously in previous regulatory analyses (U.S. EPA, 2015, 2020, 2023d), EPA assesses plants incurring costs below one percent of revenue as unlikely to face material economic impacts, plants with costs of at least one percent but less than three percent of revenue

49 Even though the majority of steam electric power plants may be able to pass increases in production costs to consumers through increased electricity prices, it is difficult to determine exactly which plants would be able to do so. Consequently, EPA concluded that assuming zero cost pass-through is appropriate as a screening-level, upper bound estimate of the potential impact of compliance expenditures on steam electric power plants and their parent entities. The analysis, while helpful to understand potential cost impact, does not generally indicate whether profitability is jeopardized, cash flow is affected, or risk of financial distress is increased.

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

51 In using the year-by-year revenue values to develop an average over the data years, EPA set aside from the average calculation any generation values that are anomalously low. Such low generating output likely results from temporary disruption in operation, such as a generating unit being out of service for maintenance.

52 EPA's first step in calculating plant revenue was to restate electricity prices in 2023 dollars using the Gross Domestic Product (GDP) deflator index published by the U.S. Bureau of Economic Analysis (BEA) (U.S. Bureau of Economic Analysis. (2023). *Table 1.1.9 Implicit Price Deflators for Gross Domestic Product (GDP Deflator)*. Retrieved from https://apps.bea.gov/iTable/?reqid=19&step=3&isuri=1&1921=survey&1903=11). These individual yearly values were then averaged and brought forward to 2024 using electricity price projections from the Annual Energy Outlook publication for 2023 (AEO2023) (U.S. Energy Information Administration. (2023b). *Annual Energy Outlook 2023*. Retrieved from https://www.eia.gov/outlooks/aeo/). AEO2023 contains projections and analysis of U.S. energy supply, demand, and prices through 2050. AEO2023 electricity price projections are in constant dollars; therefore, these adjustments yield 2024 revenue values in dollars of the year 2023 (converted from 2022 dollars to 2023 dollars).

as having a higher chance of facing material economic impacts, and plants incurring costs of at least three percent of revenue as having a still higher probability of material economic impacts.

4.2.2 Key Findings for Regulatory Options

Table 4-1 and Table 4-2 present the lower and upper bound cost-to-revenue analysis results for each of the regulatory options. Under all regulatory options analyzed, most plants would not experience compliance costs exceeding one or three percent of revenue.

Table 4-1: Plant-Level Cost-to-Revenue Analysis Results by Owner Type and Regulatory Option – Lower Bound

Owner Type	Total Number of Plants[a]	Number of Plants with a Ratio of			
		0%[a,b]	≠0 and <1%	≥1 and 3%	≥3%
Option A					
Cooperative	59	44	10	3	2
Federal	23	17	4	2	0
Investor-owned	320	238	63	14	5
Municipality	111	100	4	2	5
Nonutility	308	289	15	1	3
Political Subdivision	33	29	3	0	1
State	4	2	2	0	0
Total	**858**	**719**	**101**	**22**	**16**
Option B					
Cooperative	59	44	8	5	2
Federal	23	17	4	2	0
Investor-owned	320	237	59	17	7
Municipality	111	100	2	4	5
Nonutility	308	288	14	3	3
Political Subdivision	33	29	3	0	1
State	4	2	1	1	0
Total	**858**	**717**	**91**	**32**	**18**
Option C					
Cooperative	59	44	8	5	2
Federal	23	17	4	2	0
Investor-owned	320	237	53	23	7
Municipality	111	100	2	4	5
Nonutility	308	288	14	3	3
Political Subdivision	33	29	3	0	1
State	4	2	1	0	1
Total	**858**	**717**	**85**	**37**	**19**

a. Plant counts are weighted estimates.

b. These plants already meet discharge requirements for the wastestreams controlled by a given regulatory option and therefore are not estimated to incur compliance costs.

Source: U.S. EPA Analysis, 2024.

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Table 4-2: Plant-Level Cost-to-Revenue Analysis Results by Owner Type and Regulatory Option – Upper Bound

Owner Type	Total Number of Plants[a]	Number of Plants with a Ratio of			
		0%[a,b]	≠0 and <1%	≥1 and 3%	≥3%
Option A					
Cooperative	59	41	9	4	5
Federal	23	14	6	2	1
Investor-owned	320	224	64	19	13
Municipality	111	97	5	3	6
Nonutility	308	284	17	4	3
Political Subdivision	33	27	5	0	1
State	4	2	1	1	0
Total	**858**	**688**	**107**	**33**	**29**
Option B					
Cooperative	59	41	7	6	5
Federal	23	14	5	3	1
Investor-owned	320	223	62	20	15
Municipality	111	97	3	5	6
Nonutility	308	284	15	6	3
Political Subdivision	33	27	5	0	1
State	4	2	1	1	0
Total	**858**	**687**	**98**	**41**	**31**
Option C					
Cooperative	59	41	7	6	5
Federal	23	14	5	2	2
Investor-owned	320	223	57	25	15
Municipality	111	97	3	5	6
Nonutility	308	284	13	8	3
Political Subdivision	33	27	5	0	1
State	4	2	1	0	1
Total	**858**	**687**	**91**	**46**	**33**

a. Plant counts are weighted estimates.

b. These plants already meet discharge requirements for the wastestreams controlled by a given regulatory option and therefore are not estimated to incur compliance costs.

Source: U.S. EPA Analysis, 2024.

4.2.3 Uncertainties and Limitations

Despite EPA's use of the best available information and data, this analysis of plant-level impacts has uncertainties and limitations, including:

- The impact of the regulatory options may be over- or under-estimated as a result of differences between actual 2024 plant revenue and those estimated using EIA databases for 2015 through 2021.
- As noted above, the zero cost pass-through assumption represents a worst-case scenario from the perspective of the plant owner. To the extent that companies are able to pass some compliance costs on to consumers through higher electricity prices, this analysis overstates the potential impact of the regulatory options on steam electric power plants.

- EPA assumes that owners of plants that retire or repower during the period of analysis, but after installing equipment to comply with the final rule, will continue to amortize capital expenses over the 20-year life of the technology. To the extent that plant owners use an accelerated amortization schedule, this analysis may understate the potential impact of the baseline and regulatory options on steam electric power plants.

4.3 Cost-to-Revenue Screening Analysis: Parent Entity-Level Analysis

Following the methodology EPA used for the analysis of the 2015 and 2020 rules and 2023 proposal analyses (U.S. EPA, 2015, 2020, 2023d), EPA also assessed the economic impact of the regulatory options at the parent entity level. The cost-to-revenue screening analysis at the entity level adds particular insight on the impact of compliance requirements on those entities that own multiple plants.

EPA conducted this screening analysis at the *highest* level of *domestic* ownership, referred to as the "domestic parent entity." For this analysis, the Agency considered only entities with the largest share of ownership (*e.g.*, majority owner) in at least one surveyed steam electric power plant.[53,54] The entity-level analysis maintains the worst-case analytical assumption of no pass-through of compliance costs to electricity consumers used for the plant-level cost-to-revenue analysis in Section 4.2.

4.3.1 Analysis Approach and Data Inputs

Following the approach used in the 2015, 2020, and proposed 2023 rule analyses (U.S. EPA, 2015, 2020, 2023d), to assess the entity-level economic/financial impact of compliance requirements, EPA summed plant-level annualized after-tax compliance costs calculated in Section 3.2 to the level of the steam electric power plant owning entity and compared these costs to parent entity revenue.

Similar to the plant-level analysis, EPA used cost-to-revenue ratios of one and three percent as markers of potential impact for this analysis. Also similar to the assumptions made for the plant-level analysis, for this entity-level analysis the Agency assumed that entities incurring costs below one percent of revenue are unlikely to face significant economic impacts, while entities with costs of at least one percent but less than three percent of revenue have a higher chance of facing significant economic impacts, and entities incurring costs of at least three percent of revenue have a still higher probability of significant economic impacts.

Following the approach used in the 2015, 2020, and 2023 rule analyses (U.S. EPA, 2015, 2020, 2023d; see Section 4.3), EPA analyzed two cases that provide approximate upper and lower bound estimates on: (1) the number of entities incurring compliance costs and (2) the costs incurred by any entity owning one or more steam electric power plant.

This entity-level cost-to-revenue analysis involved the following steps: (1) Determining the parent entity; (2) Determining the parent entity revenue; and (3) Estimating compliance costs at the level of the parent

53 Throughout these analyses, EPA refers to the owner with the largest ownership share as the "majority owner" even when the ownership share is less than 51 percent.

54 When two entities have equal ownership shares in a plant (*e.g.*, 50 percent each), EPA analyzed both entities and allocated plant-level compliance costs to each entity.

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A Summary of Changes to Costs and Economic Impact Analysis

Table A-1 summarizes the principal methodological changes EPA made to analyses of the costs and economic impacts of this final ELG rule as compared to the analyses of the 2020 rule and the 2023 proposal (U.S. EPA, 2020, 2023d).

Table A-1: Changes to Costs and Economic Impacts Analysis Since 2020 Rule and 2023 Proposed Rule

Cost or Impact Category	Analysis Component (2020 Rule Analysis)	Change from 2020 Rule to 2023 Proposed Rule	Change from 2023 Proposed Rule to 2024 Final Rule
General inputs for screening-level analyses	Compliance costs discounted and annualized (7 percent)	No change	Compliance costs discounted and annualized using a weighted average cost of capital for the power sector of 3.76 percent
	Generation, plant revenue, and estimated electricity prices using EIA-861 and EIA-923 databases; six-year (2013-2018) average values	Updated with data from more current EIA-861 and EIA-923 databases to use more recent six-year [2015-2020] average values	Updated with data from more current EIA-861 and EIA-923 databases to use more recent six-year [2016-2021] average values
	Generating capacity from 2018 EIA-860	Updated using 2020 EIA-860	Updated using 2021 EIA-860
	NERC regions from 2017 EIA-860	Updated using 2020 EIA-860	Updated using 2021 EIA-860
	Electricity revenue, sales, and number of consumers by consumer class (residential, industrial, commercial, and transportation) for ASCC and HICC regions from EIA-861 for [2018]	Updated to use data from EIA-861 for [2020]	Updated to use data from EIA-861 for [2021]
	Electricity revenue, sales, and number of consumers by consumer class (residential, industrial, commercial, and transportation) for NERC regions other than ASCC and HICC regions from [2019] AEO projections	Updated using [2021] AEO projections	Updated using [2023] AEO projections
Industry profile	Total count of plants (914 plants)	Updated universe of 871 plants reflects information on actual, planned, and announced unit retirements through the end of 2028	Updated universe of 858 plants reflects information on actual, planned, and announced unit retirements through the end of 2028
	Industry data (*i.e.*, capacity, generation, number of plants, etc.) from 2018 EIA databases	Updated using 2020 EIA databases	Updated using 2021 EIA databases

Table A-1: Changes to Costs and Economic Impacts Analysis Since 2020 Rule and 2023 Proposed Rule

Cost or Impact Category	Analysis Component (2020 Rule Analysis)	Change from 2020 Rule to 2023 Proposed Rule	Change from 2023 Proposed Rule to 2024 Final Rule
Screening-level plant impacts	Cost-to-revenue impact indicators (1% and 3%) based on 6-year (2013-2018) average values of electricity generation and electricity prices (to estimate plant-level revenue)	Updated to use average electricity generation and electricity prices for [2015-2020]	Updated to use average electricity generation and electricity prices for [2016-2021]
Market-level impacts (IPM)	The Baseline includes existing regulatory requirements as of January 2020, plus the final CCR Part A rule and an updated representation of the 2015 ELG based on 2020 data.	The Baseline includes existing regulatory requirements as of August 2021 and an updated representation of the 2020 ELG based on 2021 data.	The Baseline includes regulatory requirements as of March 2023 including the Inflation Reduction Act of 2022.
Potential electricity price effects	Projected total electricity sales in [2020] from [AEO 2019]	Projected total electricity sales in [2024] from [AEO 2021]	Projected total electricity sales in [2024] from [AEO 2023]
	Electricity sales data by consumer group from [2018] EIA-860 database	Electricity sales data by consumer group from [2020] EIA-860 database	Electricity sales data by consumer group from [2021] EIA-860 database
Owner-level impacts and RFA/SBREFA	Owners identified in EIA-860 [2018]	Owners identified in EIA-860 [2020]	Owners identified in EIA-860 [2021]
	Small business size determination metrics [Dun and Bradstreet for private entities; Census ACS 2017 for governments]	Small business size determination metrics [Dun and Bradstreet for private entities; Census ACS 2019 for governments]	Small business size determination metrics [Dun and Bradstreet for private entities; Census ACS 2021 for governments]

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EXHIBIT 16

	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P	Q	R	S
1	**EPA ICR ID**	**Plant Name**	**SE Unit ID**	**Capacity (MW)**	**Retire or Fuel Conversion Year**	**FGD Regulatory Option A**	**FGD Regulatory Option A Capital Cost (2023$)**	**FGD Regulatory Option A O&M Cost (2023$/yr)**	**FGD Regulatory Option A One-Time Cost (2023$)**	**FGD Regulatory Option B**	**Least Cost (Regulatory Options B and C)**	**FGD Regulatory Option B Capital Cost (2023$)**	**FGD Regulatory Option B O&M Cost (2023$/yr)**	**FGD Regulatory Option B One-Time Cost (2023$)**	**FGD Regulatory Option C**	**Least Cost (Regulatory Options B and C)**	**FGD Regulatory Option C Capital Cost (2023$)**	**FGD Regulatory Option C O&M Cost (2023$/yr)**	**FGD Regulatory Option C One-Time Cost (2023$)**
11	1493	Plant James H Miller Jr	SE Unit-1	706		Zero Discharge	$6,347,445	$164,488	$38,285	Zero Discharge	Membrane	$6,347,445	$164,488	$38,285	Zero Discharge	Membrane	$6,347,445	$164,488	$38,285
12	1493	Plant James H Miller Jr	SE Unit-2	706		Zero Discharge	$6,305,039	$163,389	$38,030	Zero Discharge	Membrane	$6,305,039	$163,389	$38,030	Zero Discharge	Membrane	$6,305,039	$163,389	$38,030
13	1493	Plant James H Miller Jr	SE Unit-3	706		Zero Discharge	$6,305,039	$163,389	$38,030	Zero Discharge	Membrane	$6,305,039	$163,389	$38,030	Zero Discharge	Membrane	$6,305,039	$163,389	$38,030
14	1493	Plant James H Miller Jr	SE Unit-4	706		Zero Discharge	$6,305,039	$163,389	$38,030	Zero Discharge	Membrane	$6,305,039	$163,389	$38,030	Zero Discharge	Membrane	$6,305,039	$163,389	$38,030
72																			
73	Abbreviations: CP+LRTR (chemical precipitation plus low residence time reduction), SDE (spray dryer evaporator).																		
74	a - The EPA made adjustments to select electric generating units following final regulatory option cost estimation. Refer to the *Updates to Estimated Compliance Costs and Pollutant Loadings* memorandum for more information (DCN SE11780).																		
75																			

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EXHIBIT 17

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
WASHINGTON, D.C. 20460

OFFICE OF WATER

December 13, 2021

Donna B. Hill
Principal Scientist, Land & Water
Southern Company – Environmental Policy & Engagement
Bin 14N-8195 APC Corp. HQ
600 18th Street North
Birmingham, AL 35203

Dear Ms. Hill,

The U.S. Environmental Protection Agency (EPA), under the authority of the Clean Water Act, as amended (the "Act"), 33 USC 1251 et seq., published revisions to the effluent limitations guidelines and standards ("ELGs") for the steam electric power generating point source category in November 2015 and August 2020. EPA is currently evaluating possible revisions to the requirements for wastestreams included in both the 2015 and 2020 Rules. As part of this evaluation, EPA is assessing the performance and cost of wastewater management technologies associated with flue gas desulfurization (FGD) wastewater, bottom ash (BA) transport water,[1] combustion residual leachate (CRL), and legacy wastewater (e.g., from pond dewatering).

EPA appreciates your company's response to the January 2, 2018 letter requesting information pertaining to FGD wastewater, as well as your company's willingness to discuss and provide information on all aspects of the 2020 rulemaking. Because of your company's broad experience and willing cooperation, EPA is asking that you voluntarily provide information as detailed in **Parts I-III** below.

Part I: Please provide information on FGD wastewater that would update your responses to the January 2, 2018 letter. Because Southern Company continued to provide information to EPA throughout the rulemaking process, we suggest focusing on information obtained in 2021; however, you may provide performance and cost information generated earlier if it is part of a multi-year dataset or if you believe it would be helpful to the Agency.

Part II: For each power plant that your company owned or operated on or after January 1, 2020 (including associated off-site landfills), please provide relevant performance and cost data on BA, CRL, and legacy wastewaters as detailed in **Enclosure 1**.

Part III: EPA is requesting that Southern Company participate in a voluntary sampling program to sample CRL because our information indicates that Southern Company has at least one new landfill constructed pursuant to the 2015 coal combustion residuals rule at 40 CFR §257. If choosing to participate for one or more new landfills, EPA requests that Southern Company conform to the following general requirements for *each* landfill the company elects to sample under this voluntary sampling program:

[1] In addition, EPA is collecting characterization data on the overflow from under the boiler BA system purges (a low volume wastewater) and remote mechanical drag BA system purges (BA purge water).

- Where the company has already collected CRL data consistent with **Enclosure 2**, the company may submit that data; or
- Where the company has not already collected such CRL data but can sample CRL wastewater directly, the company should collect samples of untreated and treated CRL at a frequency of once per week for four consecutive weeks; and
    - Collect samples for all parameters listed in **Enclosure 2**. The company should collect the metals and mercury samples using clean sampling techniques (i.e., clean hands/dirty hands sampling techniques) described in EPA Method 1669; and
    - Obtain all necessary supplies for sample collection, and have the samples analyzed by a certified laboratory using the analytical methods specified in **Enclosure 2**; otherwise
- Where the company cannot sample CRL wastewater directly, a company should collect four grab samples of landfill solids; and
    - Generate leachate samples pursuant to EPA Methods 1313 and 1316 for all parameters listed in **Enclosure 2**; and
    - Obtain all necessary supplies for sample collection, and have the samples analyzed by a certified laboratory using EPA Methods 1313 and 1316.

Please refer to **Enclosure 2** for a description of the criteria you need to meet for participation in the sampling program, and specific instructions regarding sample collection, handling, and analysis.

EPA would appreciate a response for each of the information types described in Parts I and II by January 28, 2022 and sampling data obtained in Part III by February 16, 2022. EPA also acknowledges that in some cases you may wish to have an extension for, or decline to participate in, any of the voluntary requests. In such cases, please notify EPA by January 13, 2022. To the extent possible in responding to the requests below, EPA suggests that all materials be provided in an unredacted and unedited form to minimize the burden of their production, with the exception of edits to raw analytic data to conform with **Enclosure 3**.

Enclosure 1 of this letter details the data requested for BA, CRL, and legacy wastewaters. **Enclosure 2** of this letter describes the criteria you need to meet for participation in the sampling program, and specific instructions regarding sample collection, handling, and analysis. **Enclosure 3** of this letter details how the analytical data should be provided to EPA. **Enclosure 4** of this letter provides an example process flow diagram that should be provided in response to this request. **Enclosure 5** of this letter provides the statutory authority on which this request is based and explains your legal rights to protection of confidential business information. **Enclosure 6** is a notice of EPA's intention to allow selected contractors access to all information, including the confidential information that you submit.

If you have any questions about the information requested, please contact Tony Tripp via e-mail at anthony.tripp@epa.gov or by phone at (202) 566-1419.

Sincerely,

ROBERT WOOD

Digitally signed by ROBERT WOOD
Date: 2021.12.14 07:52:22 -05'00'

Robert K. Wood, Director
Engineering & Analysis Division (4303T)

Enclosures

Enclosure 1

Description of the Types of Voluntary Information Being Sought for Bottom Ash, Leachate, and Legacy Wastewaters

Bottom Ash: Information associated with overflow from a mechanical drag system (MDS) or compact submerged conveyor (CSC), or purge or blowdown from a remote MDS installation. Because Southern Company continued to provide information to EPA throughout the rulemaking process, we suggest focusing on information covering 2021; however, you may provide performance and cost information generated earlier if it is part of a multi-year dataset or if you believe it would be helpful to the Agency. The following identifies EPA's specific information sought related to overflow from these installations:

1. Identify the specific plant, generating unit(s), and type of system installation (i.e., under the boiler MDS).
2. For under the boiler MDS or CSC installations, provide the frequency of overflow, overflow flow rate or volume, and how the flow rate is managed (e.g., low volume sumps).
3. For remote MDS installations, provide the purge rate, purge treatment and/or management, and detailed process flow diagram of the system(s). Provide the amount of purge required (both volume and as a percentage of the total system capacity), frequency, and why a purge is required. Provide the details of evaluations done to determine if a purge from the system is necessary to maintain the system water balance.
4. Provide pollutant concentration data collected to characterize overflow from an MDS or CSC system or purge from a remote MDS system. Please provide observations for both total and dissolved parameters and pH monitoring results. See Enclosure 3 for instruction on how to provide the analytical data.

Leachate: Information associated with on-site or off-site testing (full-, pilot-, or laboratory-scale) and/or implementation of treatment technologies associated with CRL treatment. EPA is interested in information not part of its 2015 rulemaking record and suggests focusing on information covering the period since January 1, 2013. These treatment technologies may include chemical precipitation; biological treatment; thermal technology (including partial or complete evaporation); ion exchange; zero valent iron (ZVI) technology; membrane filtration technology (nanofiltration, reverse osmosis, and/or forward osmosis); paste, solidification, or encapsulation of fixation; electrodialysis; or electrocoagulation. The following identifies EPA's specific requests/questions related to the technology evaluations conducted during the specified timeframes:

1. Identify reports (including draft reports) that have been prepared documenting the technology evaluation or full-scale operation, including reports prepared by third parties such as the technology vendor or a consultant. Provide a copy of such reports with the exception of reports authored by the Electric Power Research Institute (EPRI).
2. Where no draft or final report exists as described in Item 1 above, or where your company collected supplemental information to a third-party report included in Item 1 above,

    a. Identify the specific plant, wastestream(s), and type of technology tested or installed (e.g., chemical precipitation, biological, ZVI, membrane, or evaporation), the system vendor, and the trade name associated with the evaluated system, if applicable.

    b. Identify when and for which plant and waste management unit the technology evaluation was conducted, whether the waste management unit was open or closed, and if the evaluation is ongoing.

    c. Identify and describe the objectives of the technology evaluation.

Enclosure 1

d. Provide a detailed process flow diagram for each wastestream and technology evaluation conducted, including existing or vendor-installed pretreatment and post-treatment technologies. The diagram should show the specific sampling locations and chemical addition points for the entire test configuration. See **Enclosure 4** for an example of a detailed process flow diagram.

e. Describe changes made to the pretreatment or post-treatment configuration/operations during the testing period and indicate when these changes occurred (e.g., prior to testing, during the testing period, etc). Please include changes made by the plant or vendor during the test period. For changes made to the pretreatment/post-treatment system, provide an explanation as to what and why the changes were made.

f. Describe how effluent and/or byproduct streams from the test technology were handled during the period of the test. Please include wastewater or solid streams resulting from the test technology. If post-treatment technologies were used to manage the waste/wastewater from the vendor technology being evaluated (e.g., solidification/encapsulation), provide a description of these processes and the associated results.

g. Identify the amount of wastewater treated through each of the treatment technologies (including pretreatment/post-treatment system(s)) and note changes to the flow rate throughout the test duration. For changes in the wastewater flow rate treated, explain why there was an increase/decrease in the flow rate.

h. Identify wastestreams or dilution streams commingled with the CRL prior to treatment or added within the treatment train. Identify the percent contribution of the other wastestreams/dilution streams compared to the wastewater treated in the test.

i. Provide pollutant concentration data collected during the technology test period for each of the sampling locations identified in **Item 2(d)**. EPA is particularly interested in concentration data characterizing the raw wastewater, pretreatment effluent/test influent, treated wastewater effluent, and intermediate sample locations for the technology evaluation. Please provide observations for both total and dissolved parameters, as well as speciation data (e.g., selenite, selenate), if measured by the analytical laboratory. See **Enclosure 3** for instruction on how to provide the analytical data.

3. Please provide the laboratory reports associated with the analytical data specified in **Item 2(i)** or supplemental laboratory reports supporting **Item 1** which were not included as an attachment or appendix to such reports.

Legacy: Information associated with on-site or off-site testing (full-, pilot-, or laboratory-scale) and/or implementation of treatment technologies associated with surface impoundment decanting or dewatering treatment. EPA is interested in information not part of its 2015 rulemaking record and suggests focusing on information covering the period since January 1, 2013. These treatment technologies may include chemical precipitation; biological treatment; thermal technology (including partial or complete evaporation); ion exchange; zero valent iron (ZVI) technology; membrane filtration technology (nanofiltration, reverse osmosis, and/or forward osmosis); paste, solidification, or encapsulation or fixation; electrodialysis; or electrocoagulation. The following identifies EPA's specific requests/questions related to the technology evaluations conducted during the specified timeframes:

1. Identify reports (including draft reports) that have been prepared documenting the technology evaluation or full-scale operation, including reports prepared by third parties such as the technology vendor or a consultant. Provide a copy of such reports with the exception of reports authored by the Electric Power Research Institute (EPRI).

2. Where no draft or final report exists as described in **Item 1** above, or where your company collected supplemental information to a third-party report included in **Item 1** above,

Enclosure 1

a. Identify the specific plant, wastesream(s), and type of technology tested or installed (e.g., chemical precipitation, biological, ZVI, membrane, or evaporation), the system vendor, and the trade name associated with the evaluated system, if applicable.

b. Identify when and for which plant the technology evaluation was conducted, the surface impoundment(s), whether decanting or dewatering was being performed, and if the evaluation is ongoing.

c. Identify and describe the objectives of the technology evaluation.

d. Provide a detailed process flow diagram for each wastestream and technology evaluation conducted, including existing or vendor-installed pretreatment and post-treatment technologies. The diagram should show the specific sampling locations and chemical addition points for the entire test configuration. See **Enclosure 4** for an example of a detailed process flow diagram.

e. Describe changes made to the pretreatment or post-treatment configuration/operations during the testing period and indicate when these changes occurred (e.g., prior to testing, during the testing period, etc). Please include changes made by the plant or vendor during the test period. For changes made to the pretreatment/post-treatment system, provide an explanation as to what and why the changes were made.

f. Describe how effluent and/or byproduct streams from the test technology were handled during the period of the test. Please include wastewater or solid streams resulting from the test technology. If post-treatment technologies were used to manage the waste/wastewater from the vendor technology being evaluated (e.g., solidification/encapsulation), provide a description of these processes and the associated results.

g. Identify the amount of wastewater treated through each of the treatment technologies (including pretreatment/post-treatment system(s)) and note changes to the flow rate throughout the test duration. For changes in the wastewater flow rate treated, explain why there was an increase/decrease in the flow rate.

h. Identify wastestreams or dilution streams commingled with the legacy wastewater prior to treatment or added within the treatment train. Identify the percent contribution of the other wastestreams/dilution streams compared to the wastewater treated in the test.

i. Provide pollutant concentration data collected during the technology test period for each of the sampling locations identified in **Item 2(d)**. EPA is particularly interested in concentration data characterizing the raw wastewater, pretreatment effluent/test influent, treated wastewater effluent, and intermediate sample locations for the technology evaluation. Please provide observations for both total and dissolved parameters, as well as speciation data (e.g., selenite, selenate), if measured by the analytical laboratory. See **Enclosure 3** for instruction on how to provide the analytical data.

3. Please provide the laboratory reports associated with the analytical data specified in **Item 2(i)** or supplemental laboratory reports supporting **Item 1** which were not included as an attachment or appendix to such reports.

Cost Data: Information from bids, cost estimates, or final contracts received from vendors or engineering firms (e.g., engineering, procurement, and construction (EPC) firms) for full scale system installation corresponding to the responses for CRL and legacy wastewater above. Please provide the bids as they were submitted by the vendor or EPC firm, regardless of whether the system has been installed at the plant. If not included in the bid documentation, please also include the following information:

1. Identify the specific plant, type of technology reflected in the bid (e.g., biological, ZVI, membrane, or evaporation), the system vendor, and the trade name associated with the evaluated system, if applicable.

Enclosure 1

2. System influent characteristics used as specifications for the vendor technology (e.g., wastewater concentrations if vendor is responsible for providing pretreatment, pretreatment effluent concentrations if vendor is not responsible for pretreatment).
3. Design flow rate of the treatment system.
4. Treatment system components (e.g., pretreatment elements, post treatment elements).
5. Other bid details communicated to the vendor to generate the bid.

Enclosure 2

Criteria for Participation in the Voluntary Sampling Program and Instructions for Sample Collection and Analysis

Criteria for Participation in Voluntary CRL Sampling Program

For the data to be relevant for EPA's assessment, the data you submit must adhere to the following conditions:

- **At least 80 percent of the water volume being sampled must be CRL.**
- The data should reflect typical operating conditions and be representative of properly operating treatment systems.
- The samples collected should be analyzed by certified laboratories using EPA-approved analytical methods, should have method-specified quality assurance/quality control analyses performed, and submitted in the format specified in **Enclosure 3**.

Overview of the Sampling Program

You are responsible for collecting and analyzing samples for the voluntary sampling program. This includes the following:

- Obtaining the supplies and equipment necessary for collecting the required samples (either directly from a supplier or from the contracted analytical laboratory).
- Collecting and preserving samples in accordance with the specified analytical methods.
- Packaging and shipping samples appropriately (where necessary).
- Having the wastewater samples analyzed by certified laboratories capable of meeting requirements of the EPA-approved analytical methods specified for each parameter.
- Documenting the sample collection and analysis activity.
- Collecting all supplemental information required as part of the sampling program.

All samples should be collected and analyzed as detailed in these instructions and submitted to EPA by February 16, 2022.

Sample Location and Frequency

In general, each participating plant shall collect grab samples of untreated and treated CRL from at least one new landfill constructed pursuant to the 2015 coal combustion residuals rule at 40 CFR §257. The untreated CRL should be sampled at the location where it is collected prior to treatment (e.g., from a collection basin where CRL from multiple units is commingled prior to flowing into an impoundment). The samples of treated combustion residual leachate shall be collected from the effluent of the treatment system (or surface impoundment) prior to discharge or commingling with other process wastewaters.

Each participating plant shall collect a sample of untreated CRL at least once per week for four consecutive weeks. If only one sample per week is collected, the samples shall be collected at least five days after the previous sample was collected.

Sample Collection

Samples must be collected in accordance with the requirements of the analytical methods. The plant must use clean sampling techniques when collecting the total metals and total mercury samples;

Enclosure 2

therefore, the sampling team should follow the clean hands/dirty hands sampling techniques outlined in EPA Method 1669. All samples shall be preserved as required by the method and transferred to the analytical laboratory performing analysis within the hold times specified by the method.

Sample Analysis

Table 1 specifies the list of parameters and recommended analytical methods for the voluntary sampling program. In general, you may use any EPA-approved methods listed in 40 CFR Part 136 for the parameters, so long as the analytical method chosen is at least as sensitive as the method(s) listed in Table 1. It is the responsibility of the plant to identify analytical laboratories capable of analyzing each wastewater sample in accordance with the methods selected.

Table 1. Parameters and Recommended Analytical Methods for the Voluntary Combustion Residual Leachate Sampling Program

Parameter	Recommended Methods [a]
Classicals	
Ammonia as nitrogen	EPA 350.1
Nitrate-Nitrite (as N)	EPA 353.2
Total dissolved solids (TDS)	SM 2540 C-2011
Total suspended solids (TSS)	SM 2540 D-2011
Total Kjeldahl nitrogen (TKN)	EPA 351.2
Total phosphorus	EPA 365.1
Bromide	EPA 300.0
Chloride	EPA 300.0
Iodide	EPA 300.0
Fluoride	EPA 300.0
Sulfate	EPA 300.0
Sulfite	SM 4500-SO_3–B-2011
Metals (Total Recoverable)	
Aluminum, antimony, arsenic, beryllium, cadmium, chromium, cobalt, copper, lead, manganese, molybdenum, nickel, potassium, selenium, silver, thallium, vanadium, and zinc	EPA 200.8
Barium, boron, calcium, iron, lead, magnesium, silica, sodium, strontium, tin, and titanium	EPA 200.7 EPA 200.8
Mercury	EPA 1631 E

a – The method used must be approved under 40 CFR Part 136, if the analyte is listed in 40 CFR Part 136. Make sure the approved revision of the method is used. The Standard Methods listed are approved as of November 16, 2017.

Reporting Sample Data

After receiving the analytical results from the laboratory, the participating plants shall enter the analytical data into the "Analytical Data Table" workbook. Plants shall report all results, including those below the reporting limit. Plants shall identify results that are less than the MDL, and results that are between the detection and reporting limits. For example, if the MDL is equal to 5 ng/L, the reporting limit is equal to 15 ng/L, and the value reported by the laboratory is 12 ng/L, the sampled plant should report 12 ng/L as the measured value and identify and describe any qualifiers on the data in the corresponding column. If the measured value is not detected, list the detection limit value and select the less than (<) symbol in the non-detect indicator column.

Enclosure 2

Quality Assurance/Quality Control

Follow the method-specified quality assurance/quality control analyses and attach a data review summary once the analyses are complete.

Enclosure 3

Guidelines for Submitting Analytical Data for the Steam Electric Power Generating Effluent Guidelines Supplemental Rulemaking

This document provides guidance regarding the submission of analytical data and supplemental information which is not included in a report or other narrative document. The data you submit should reflect typical operating conditions and be representative of properly operating treatment systems. Data you submit should be relevant to **FGD wastewater, BA transport water, CRL, and/or legacy wastewater**.

Data Submission Format and Criteria

To facilitate EPA's analysis and use of the analytical data, the data should be submitted using the workbook format provided in Attachment 1 titled "Analytical Data Table." Included within the workbook are three worksheets. The spreadsheet titled "Data Table Structure" identifies the information required for each individual sampling result and provides the table for entering the analytical data. The spreadsheet titled "Example Data Table" includes three example entries to provide some context of how to populate each of the fields in the data table. Finally, the spreadsheet titled "Field Descriptions" describes each field included in the data table. Provide the individual sample results associated with each of the sampling locations. The following is the information that should be provided for each individual sampling result, as applicable (see the "Field Descriptions" spreadsheet for more details):

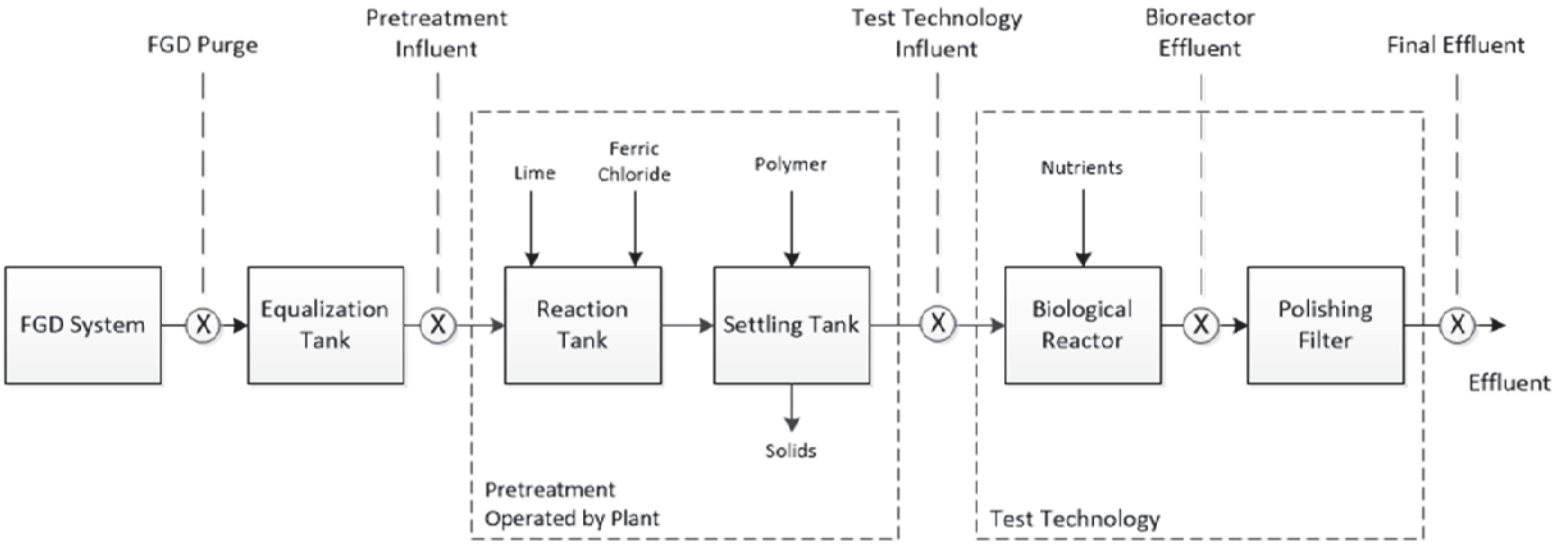
- Plant Survey ID (from the Questionnaire for the Steam Electric Effluent Guidelines).
- Plant Name.
- Date Sample Collected.
- Analyte (for metals, including whether it is total recoverable or dissolved).
- CAS Number.
- Analytical Method.
- Type of Sample Collected (e.g., grab, 24-hour composite).
- Type of Sample Analyzed (e.g., total recoverable, dissolved).
- Units.
- Non-Detect Indicator.
- Concentration.
- J-Value Concentration.
- Detection Limit.
- Reporting Limit.
- Dilution Factor.
- Qualifiers.
- Qualifier Description.
- Wastestream represented by result.
- Flow rate.
- Sample point description.
- System upset description.

Provide a separate copy of Attachment 1 for each technology/wastestream evaluated at each plant. Please include the name of the plant and the name of the technology in the file name using the following naming convention:

Analytical Data Table_Plant Name_Technology Name_Test Start Date (MMDDYYYY)

Enclosure 4

Example Process Flow Diagram for Technology Evaluation



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Enclosure 5

Confidentiality

For information provided under this voluntary request, you may, if you desire, assert a business confidentiality claim covering part or all of the information that you furnish to EPA.

EPA regulations concerning confidential business information are contained in 40 CFR Part 2, Subpart B. The manner of asserting such a claim is specified in 40 CFR 2.203(b). Information covered by such a claim will be disclosed by EPA only to the extent, and by means of the procedures, set forth in Subpart B.

If you wish to claim as confidential any of the information covered by the enclosed request, you must do so at the time you submit the information to EPA. If no such claim accompanies the information when EPA receives it, EPA may make the information available to the public without further notice to you.

EPA will notify you in the event that a request is made for release of information that you have claimed to be confidential or EPA otherwise decides to make a determination as to whether or not such information is entitled to confidential treatment. At that time, EPA will request that you substantiate any claim you have made that information is confidential. Therefore, we encourage you to consult 40 CFR Part 2, and to claim as confidential only those items that you truly believe satisfy the criteria for confidentiality.

Note that effluent data are not eligible for confidential treatment (see 40 CFR 2.302).

Enclosure 6

Notice of Intent to Transfer Confidential Information to Selected EPA Contractors

EPA intends to grant access to any confidential information collected as part of the steam electric effluent guidelines rulemaking to selected EPA contractors.

In accordance with 40 CFR Sections 2.301(h)(2-3), 2.302(h)(2-3), and 2.305(h)(2-3), EPA may allow those contractors identified below access to all data (including data claimed to be confidential) collected as part of this data request. Transfer of this information to these contractors is necessary in order for the contractors to assist EPA in performing technical, statistical, and environmental analyses to support the reconsideration of effluent limitations guidelines and standards for the steam electric power generating industry.

The contractors and subcontractors that will be providing support to EPA during the development of these regulations are listed below:

EPA Office Receiving Support	Contractor Name	EPA Contract No.	Type of Support
Office of Water/ Office of Science & Technology/Engineering & Analysis Division	Eastern Research Group, Inc.	EP-C-17-041	Engineering, environmental, and statistical analysis

EPA has determined that it is necessary to transfer the information described above to the designated contractors and subcontractors in order that they may carry out the work required by their contracts. The contracts contain all provisions necessary to implement the confidentiality regulations (see 40 CFR 2.301(h)(2), 2.302(h)(2), and 2.305(h)(2)).

In accordance with these confidentiality regulations, you are entitled to provide comments to EPA regarding this notice of contemplated disclosure. Any such comments must be received by EPA in writing within 10 days of your receipt of this notice. Please send such comments to:

Tony Tripp
USEPA Headquarters
William Jefferson Clinton Building
1200 Pennsylvania Ave., N.W. (Mail Code: 4303T)
Washington, DC 20460
anthony.tripp@epa.gov

EXHIBIT 18

Southern Company

Southern Company Services, Inc.
600 18th Street North
Bin 14N-8195
Birmingham, AL 35203
205 257 5234 tel
205 587 4846 cell
dbhill@southernco.com

April 1, 2022

Robert K. Wood
Director, Office of Water, Engineering & Analysis Division
U.S. Environmental Protection Agency
William Jefferson Clinton Building
1200 Pennsylvania Ave., N.W.
Washington, D.C. 20460

Re: **Request for Voluntary Submission of Data/Information to Support ELGs Rulemaking**

Dear Mr. Wood:

This letter and the enclosed electronic files constitute the response of Southern Company Services, Inc., on behalf of The Southern Company and its subsidiaries,[1] (hereinafter, collectively, "Southern" or "the Company"), to the U.S. Environmental Protection Agency's ("EPA" or "Agency") December 13, 2021 request (hereinafter "Request") for information regarding "performance and cost of wastewater management technologies associated with flue gas desulfurization (FGD) wastewater, bottom ash (BA) transport water," including "characterization data on the overflow from under the boiler BA system purges (a low volume wastewater) and remote mechanical drag BA system purges (BA purge water)," "combustion residual leachate (CRL), and legacy wastewater (e.g., from pond dewatering)."

Southern appreciates the opportunity and additional time to voluntarily provide data and information pertaining to the development of potential revisions to the 2020 ELG Rule.[2] As discussed in this letter, Southern has made, and continues to make, significant investments in FGD wastewater treatment to comply with the 2020 ELG Rule. Southern urges EPA to view the additional context provided in this letter as inextricable from the data and information, as the context speaks to a vast amount of research and knowledge gained from the installation and operation of treatment systems and to the significant investments made on behalf of Southern's customers. Southern also recognizes and appreciates the opportunity EPA has to ensure that any new ELG rulemaking preserves features such as compliance subcategories that facilitate, rather than hinder, the important and rapidly evolving industry transition to a low-carbon future. Southern is open to future engagement with EPA to address any questions related to the data and information submitted with this letter.

Background

EPA initially requested a response to Parts I and II of the Request by January 28, 2022. On January 12, 2022, Southern submitted a written request seeking an extension of its response date to March 14, 2022, due to the volume of information sought by EPA, among other things. On January 13, 2022,

[1] Southern Company is a holding company that conducts its business through its subsidiaries; accordingly, unless the context otherwise requires, references in this letter to Southern Company's operations, such as generating activities, refer to those operations conducted through its subsidiaries.
[2] 85 Fed. Reg. 64,650 (Oct. 13, 2020).

through email correspondence with Ms. Donna Hill, Mr. Anthony Tripp granted Southern's requested extension. Due to ongoing discussions with third-party vendors regarding potentially relevant data and information in Southern's possession, Southern requested an additional extension on March 9, 2022. In response, EPA requested receipt of the Company's response by April 1, 2022. Southern appreciates the additional time EPA granted the Company to respond to the Request.

Southern's response to this Request is voluntary. Except for documents specifically generated to respond to this Request, Southern has limited its production to information in its possession on or before December 13, 2021.

The electronic files produced by Southern have been gathered through a diligent process of review for responsiveness, confidentiality, and privilege. With respect to any potentially responsive information protected by the attorney-client privilege and/or attorney work product doctrine, Southern asserts these privileges and withholds such information.

The electronic files responsive to the Request that contain information Southern and its vendors consider to be confidential are marked "Business Confidential, 40 C.F.R. Part 2" and/or have been designated as confidential in the electronic file name.[3] This marked/designated data and information is entitled to confidential treatment under EPA's Part 2 regulations and other applicable law because the information is customarily kept private by Southern and its vendors, disclosure of the information is likely to cause substantial harm to Southern and its vendors competitive positions, and additionally and alternatively, the information is being submitted voluntarily and is not customarily disclosed to the public. 40 C.F.R § 2.208.[4]

Accordingly, EPA is not authorized to disclose this data and information to the public. Southern has attempted to provide accurate responses and complete productions to each part of the Request. The Company reserves the right to supplement this initial submittal if additional data or information responsive to the Request becomes known or available to Southern.

Responses to Parts I through III of EPA's Request

Provided below are Southern's narrative responses to Parts I through III of EPA's Request, including an explanation of the electronic files produced with this correspondence.

Part I: Please provide information on FGD wastewater that would update your responses to the January 2, 2018 letter. Because Southern Company continued to provide information to EPA throughout the rulemaking process, we suggest focusing on information obtained in 2021; however,

[3] For these materials, Southern asserts a claim of confidentiality pursuant to the procedures set forth in 40 C.F.R. Part 2 and the protections of 5 U.S.C. § 552(b)(4), 18 U.S.C. § 1905, and other applicable law, including but not limited to the standards established in *Food Mktg. Inst. v. Argus Leader Media*, 139 S. Ct. 2356, 2366 (2019).

[4] As stated in EPA's Request and pursuant to EPA's regulations, should EPA provide Southern with a notice and request for substantiation of its claims pursuant to 40 C.F.R. § 2.204, Southern will provide the necessary justification.

you may provide performance and cost information generated earlier if it is part of a multi-year dataset or if you believe it would be helpful to the Agency.

Response:

Southern has contemporaneously provided facility-specific responses to the individual items in the January 2, 2018 Section 308 request via a secure file transfer portal. The files are organized by operating company, then Part, then wastewater stream, and then facility (e.g., "[Operating Company] > Part I > FGD Wastewater > [Facility]"). Within each facility folder, the ". . . – Narrative" electronic file includes responses to some items of the 2018 Section 308 request, but also identifies the second set of information responsive to that item, namely, documents and/or data responsive to EPA's Request.

The information provided by the Company in response to Part I includes relevant final reports, performance data, and cost information for FGD wastewater. The information provided is predominantly from 2021, although Southern has provided some earlier information relevant to this response. Furthermore, the Company has not attempted to secure all potentially relevant data it, Southern subsidiaries, and/or vendors may possess. Instead, Southern has provided a representative data set that demonstrates the performance capabilities of the treatment technologies and associated costs.

In the discussion below, Southern offers additional context related to the data and information submitted, as it is likely to be used by EPA in the development of a potentially revised set of effluent limitations applicable to FGD wastewater. Southern encourages EPA to view these additional considerations as inextricable from the data and information.

Technology development and operational experience

Southern's technology development efforts, operational experience, and ongoing investments have resulted in valuable accumulated knowledge regarding the performance of technologies for treating FGD wastewater. Since the promulgation of the 2015 ELG Rule,[5] Southern has been proactive in attempting to develop efficient means for controlling FGD wastewater discharges. Specifically, Southern, the Electric Power Research Institute ("EPRI"), Southern Research Institute ("SRI"), and 14 other entities created a state-of-the-art center that focuses on finding new ways to reduce, conserve and improve the quality of water returned to the environment from power plants. This center was previously known as the "Water Research Center" ("WRC") but is now referred to as the Water Research and Conservation Center ("WRCC") and is comprised of centers located at Georgia Power Company's ("Georgia Power") Plants Bowen and McDonough-Atkinson. The WRCC has tested multiple potential treatment solutions for current water challenges, as well as those anticipated in the future. One area of WRCC focus has been evaluating the technology EPA identified as Best Available Technology Economically Achievable ("BAT") in the 2015 ELG Rule for FGD wastewater, which is chemical precipitation treatment followed by SUEZ's (formerly General Electric's) ABMet biological technology. In addition, several other technologies have been evaluated at the WRCC to determine whether they can consistently treat FGD wastewater to comply with applicable BAT effluent

[5] 80 Fed. Reg. 67,838 (Nov. 3, 2015).

limitations. These included technologies from Frontier Water Systems, Inotec, Evoqua, Liberty Hydro, and an in-house, biofilm technology.

Apart from the WRCC, Southern subsidiaries have undertaken efforts at individual facilities to evaluate which technologies may be able to help achieve compliance with the BAT effluent limitations for FGD wastewater. For example, Alabama Power Company ("Alabama Power") has installed a full-scale operational chemical precipitation + biological + ultrafiltration ("UF") treatment system at Plant Miller, including additional denitrifying sand filters and arsenic polishers. The system was contracted in 2017 and 2018 to achieve compliance with the 2015 ELG limits for FGD wastewater and projected water quality limits in the then-pending NPDES permit renewal. The system was commissioned in 2019 and 2020. Process tuning to bring the system into consistent ELG compliance continued through 2021 and is ongoing in 2022. As explained in the attached Miller FGD narrative, overall operational experience suggests that the 2020 ELG limitations are appropriate BAT and represent the technological limit of the systems available to the industry for treatment of FGD wastewater.

Costs

The costs (e.g., time and resources) of evaluating and implementing these treatment technologies are substantial. If the Agency chooses to revise the 2020 ELG limitations, then Southern encourages EPA to do so in a manner that avoids the potential for stranded investments in the research, development, and—in some cases—construction of treatment systems designed to satisfy the technology-based effluent limitations based on chemical precipitation and biological wastewater treatment technologies. To address our cost concerns, Southern encourages EPA to continue to accommodate, or even expand, the four factors currently prescribed in 40 C.F.R. § 423.11(t), to allow sufficient time to adjust to further regulatory revision, and where necessary incorporate the public regulated utility approval processes.

A shift in the model technology or associated effluent limitations could marginalize the time and resources spent researching, evaluating, and installing technologies previously endorsed by the Agency. If EPA's new rulemaking seeks to establish new limits based on the installation and operation of different technologies at substantial additional costs, the Agency should incorporate measures in the regulations to ensure that entities who have made investments of money and time to comply with the earlier rulemakings may continue to rely on those investments for future ELG compliance.

Membrane-based systems

As EPA has now recognized in both the 2015 and the 2020 ELG Rules, membrane-based systems are neither technically nor economically available on a nationwide basis, and that fact has not changed in the eighteen months since the rule was finalized. For instance, some of the information submitted by Southern includes analysis of a Vibratory Shear Enhanced Process ("VSEP") system. VSEP is not a mature, widely available solution for treating FGD wastewater, and it is not likely to be in the near future. Membranes represent only one component of the total treatment controls necessary for controlling FGD wastewater discharges. The uncertainties and challenges with the total treatment controls are further explained below and are clearly illustrated in the attachments.

Southern has studied membranes in a limited capacity at Plant Bowen to understand permeate production rates and has deployed VSEP only at the pilot scale at Georgia Power's Plant Scherer. VSEP is not yet proven as a commercially available technology and has not been operated at a commercial scale for treatment of FGD wastewater. Southern's preliminary analysis suggests that membrane-based treatment may be viable under certain conditions that can be achieved at Plant Scherer. These conditions include limited flow rates as well as low levels of chlorides and total dissolved solids that might allow a viable permeate recovery rate. Because those favorable conditions can be found at Plant Scherer, along with the preliminary results of the ongoing pilot noted above, Georgia Power filed a Notice of Planned Participation in the Voluntary Incentives Program. This submittal was made prospectively, as membranes could be, with additional research, a part of a viable ELG compliance solution for Plant Scherer. However, the Company's cautious approach to membrane-based treatment is illustrated by the ELG compliance strategy for Plant Scherer as presented to the Georgia Public Service Commission. That strategy, provided in the 2022 Integrated Resource Plan, remains chemical precipitation + biological + UF treatment while evaluations are ongoing regarding the membrane-based treatment system.

Even if membrane-based technology matures to the point of commercial scale demonstration, it will still present significant costs, some of which remain difficult to fully quantify. Plant Scherer, for example, has already made costly investments into infrastructure changes to manage flow rates and the associated water storage needs for FGD wastewater, and these costs are not necessarily fully reflected in the forward-looking documents submitted herein. Those documents also only provide screening-level (-30% to +70%) cost estimates, and as such the uncertainty range of these costs remains very high. Membrane-based treatment of FGD wastewater poses significant challenges that the Company continues to study, such as high parasitic loads, electricity supply needs, membrane performance degradation, as well as on-going maintenance and membrane cleaning cycles that will require significant equipment redundancy to avoid power plant outage and performance risks. These technical challenges cannot be solved merely by adding membrane-based systems to existing chemical precipitation + biological systems as a final "polishing" step.

It cannot be overstated that membranes alone are not a compliance technology but instead a volume-reduction process that needs to be coupled with additional wastewater treatment technology, as well as processes and equipment for managing the concentrate. Managing these concentrate streams poses significant technical and economic challenges that are still under evaluation at Plant Scherer. Concentrate management options under consideration at Plant Scherer include ash encapsulation, spray dryer evaporation, and thermal evaporation or crystallization. Each option poses unique challenges related to operational performance, waste management, costs, plant operations integration, and plant dispatch requirements. These challenges increase greatly at plants with higher levels of chlorides or higher FGD wastewater flow rates. These systems pose significantly greater challenges than standard UF methods, primarily due to issues related to managing the byproducts of the technology.

The enclosed reports and data document the significant volumes of membrane concentrate that will need to be managed if these types of systems are deployed for FGD wastewater treatment. Southern has been a national leader in the research and development of membrane treatment systems for FGD wastewater, but, even under the controlled conditions of demonstration or pilot-scale research systems, the permeate recovery rates of these membranes have been inconsistent. The enclosed

information clearly reflects this inconsistency and reflects that even a well operated and maintained membrane system will likely only achieve a maximum recovery rate approaching 80% under ideal operating conditions, and that rate will most certainly rapidly decrease to nearer 70% as the membrane performance degrades.[6]

It is important to note that the specific FGD wastewater conditions present at Plant Scherer either do not exist or are unlikely to be obtained at other Southern facilities.[7] Even if they could be obtained, the problems of membrane recovery rates mentioned above would be further compounded at plants with higher flow rates, such as Plant Bowen and Plant Miller, which would have large volumes of concentrate requiring management. For example, Plant Bowen would most likely need to loosen the plant's water balance to realize chloride concentrations compatible with a membrane-based treatment solution. In effect, this would approximately double the total volume of FGD wastewater requiring treatment, taking the currently achieved flow rate of 750 gallon per minute ("gpm") and reversing this progress to a level of 1,500 gpm. This in turn will result in volumes of concentrate as high as 0.75 million gallons per day needing management and disposal. Therefore, Southern's experience suggests that membrane technology and associated brine concentrate management and disposal is not technically feasible or the best treatment option economically for sites like Plant Bowen.

Part II: For each power plant that your company owned or operated on or after January 1, 2020 (including associated off-site landfills), please provide relevant performance and cost data on BA, CRL, and legacy wastewaters as detailed in Enclosure 1.

Response:

Southern is providing information responsive to Part II of EPA's Request for CRL and legacy wastewaters. As with Part I, Southern has contemporaneously provided facility-specific responses via a secure file transfer portal. The files are organized by operating company, then Part, then wastewater stream, and then facility. Within each facility folder, the ". . . – Narrative" electronic file includes responses to some items of EPA's Request, but also identifies the second set of information responsive to that item, namely, documents and/or data responsive to the Request.

There is no data responsive to the bottom ash transport water ("BATW") portion of EPA's Request, and, therefore, this part of the Request is inapplicable.

Legacy Wastewater

Response:

[6] See enclosed *CBI - GPC Plant Bowen VSEP Operations Report*, and *CBI - GPC Plant Bowen VSEP Evaluation.*

[7] In fact, significant additional time for further research and development to pursue a viable membrane-based treatment system is still needed at Plant Scherer, the one Southern facility with conditions conducive to this technology.

Southern has provided 11 sets of electronic files responsive to this legacy wastewater portion of EPA's Request. The relevant files can be found in the "[Operating Company] > Part II > Legacy Wastewater" folder organization. In many cases, the information in these documents or data is self-evident and can be analyzed as efficiently by EPA as by the Company.

Nonetheless, the Company must also stress the context of or qualifications to the information in these documents as they relate to potential identification of BAT for the steam electric power generating point source category.

Although the content varies for each facility, Southern's response provides available and representative treatment system performance data for facilities that are dewatering. Cost and design information is also provided. Not all systems have commenced dewatering at this time, and some remain in the contracting/installation process.

Paired influent and effluent data were provided to best demonstrate the treatment technology removal of pollutants. Southern attempted to provide data in the format that EPA requested; however, it would have been burdensome to provide the data as requested in all cases. For Alabama Power, all the enclosed influent and effluent data were collected and analyzed by Alabama Power. For Georgia Power, influent and effluent data may be provided by the vendor or Georgia Power. Furthermore, the companies have not attempted to secure all potentially relevant data vendors may possess. Instead, the companies have provided a representative data set that demonstrates the capabilities of the treatment technologies.

Collectively, the information Southern has provided represents the Company's standard treatment process for this wastestream. The performance of legacy wastewater treatment systems is well demonstrated across the Company's operations, and the enclosed information provides both treatment efficiency and cost data that can be used to support a proposal for what constitutes BAT for this wastestream. The Company believes the enclosed information supports the use of mechanical treatment systems performing solids separation with flocculant/coagulant aided ballasted clarification followed by particle filtration as a polishing step. This level of legacy wastewater treatment comes at significant cost but is demonstrated at a consistent level of performance at each site. The data being provided herein, and the data being provided to the state agencies, reflect a level of treatment performance that meets existing technology-based effluent limits and is also fully protective of receiving stream water quality.

Cost data has been provided based on final accepted bids only. "Total Installed Cost" includes the equipment cost plus installation costs. This term should be considered synonymous with "project cost" or "total project cost." Installation costs refer to all costs beyond the equipment purchase cost that are required for the complete project or installed cost.

Leachate

Response:

Southern has provided data associated with a leachate treatability study at Alabama Power's Plant Gorgas. The relevant files can be found in the "Alabama Power Company > Part II > Combustion Residual Leachate" folder organization.

Southern otherwise has limited data specifically pertaining to treatment of CRL, as this wastestream is currently co-managed and treated with other wastewaters. However, if EPA concludes that revised BAT is necessary for this wastestream, Southern believes the technologies currently being used for legacy wastewater management are an appropriate consideration that may be technologically available and potentially cost-effective. EPA should also carefully consider the often-remote location of these systems, as well as the long-term decline in flows that are expected to occur following closure. As such, the Company believes passive treatment systems will be far better suited controls for management of CRL in the long-term. To support this, the Company requests that any regulatory proposal accommodate the necessary time for further study and analysis of passive treatment systems as a long-term environmentally and economically sustainable approach.

Part III: EPA is requesting that Southern Company participate in a voluntary sampling program to sample CRL because our information indicates that Southern Company has at least one new landfill constructed pursuant to the 2015 coal combustion residuals rule at 40 CFR §257

Response:

Southern subsidiaries do not have any new landfills constructed pursuant to the CCR Rule at 40 C.F.R. Part 257, Subpart D. Accordingly, this part of EPA's Request is inapplicable. Some facilities have existing landfills that have leachate collection systems that are similar in design, but there are no dedicated treatment systems for CRL. Instead, CRL is commingled with other wastewater and stormwater prior to treatment and discharge. Any sampling data collected pursuant to this Request would not provide the Agency with the data it needs to evaluate treatment performance of CRL.

Conclusion:

The enclosed information and responses provided above illustrate that EPA's previous determination that chemical precipitation followed by biological and UF treatment constitutes BAT for FGD wastewater was appropriate and should remain. Membrane filtration is not BAT for FGD wastewater but may be a viable solution at limited facilities due to site-specific conditions. Further, EPA's previous consideration of the pending retirement of generating units and the disproportionate costs that would be incurred at those facilities was also appropriate, therefore the permanent cessation of coal subcategory should also remain in the rule. In addition, Southern Company has provided considerations for EPA in setting potentially revised BAT for legacy wastewater, illustrating that the treatment systems currently being deployed across Southern's operations are available, albeit at significant cost. Finally, the Company suggests a reasonable approach for how EPA could potentially revise what constitutes BAT for CRL from existing sources, taking into account existing on-site

treatment systems as well as often remote locations of landfills and the long-term decline in CRL flows that will occur following closure.

As previously mentioned, Southern appreciates the opportunity and additional time to compile this critical data and information and is open to future engagement with EPA as an opportunity to provide additional context and respond to any questions the Agency may have prior to developing a revised regulation.

Sincerely,

Donna Hill

Digitally signed by Donna Hill
Date: 2022.03.31 15:01:17
-05'00'

cc:
Richard Benware
Tony Tripp

EXHIBIT 19

Declaration

I, Craig Grooms, declare as follows:

1. I am the Chief Operating Officer at Buckeye Power, Inc. ("Buckeye"). I am over the age of 18 years, and I am competent to testify concerning the matters in this declaration. I have personal knowledge of the facts set forth in this declaration, and if called and sworn as a witness, could and would competently testify to them.

2. I have almost three decades of experience in electricity generation, and I have been employed at Buckeye since 2004. I hold a Bachelor of Science degree in Electronic Engineering Technology from the University of Dayton, as well as a Master of Business Administration degree from Otterbein University.

3. As Chief Operating Officer at Buckeye, I am responsible for the management and direction of Buckeye's engineering and operations functions, including power delivery, engineering, information technology and resources, and market operations.

4. Buckeye is a member of the Utility Water Act Group ("UWAG"). This declaration is submitted in support of the litigation challenging EPA's final rule entitled *Supplemental Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category*, 89 Fed. Reg. 40,198 (May 9, 2024) ("the Rule").

5. I am familiar with Buckeye's operations, including generation and transmission, regulatory compliance, workforce management, and electric markets in general. I also am familiar with the Rule, and I am familiar with how the Rule will affect Buckeye as well as its suppliers, members, consumers, and employees.

Background on Buckeye

6. Buckeye is an Ohio non-profit corporation operating according to a cooperative business model. Buckeye commenced commercial operations in 1959 and provides wholesale electric service to its 25 members, which includes all electric distribution cooperatives engaged in the sale of electricity within the State of Ohio. The retail service area of Buckeye's members covers a substantial part of the land area of the state of Ohio and extends into portions of 77 of Ohio's 88 counties. Buckeye's members currently serve approximately 400,000 consumers, 91% of whom are classified as residential (farm and nonfarm).

7. Buckeye is fully committed to environmental stewardship. In recent years, Buckeye has spent **well over $1 billion** installing state-of-the-art, high-performing selective catalytic reduction and jet bubbling reactor flue gas desulfurization equipment, as well as converting from wet to dry fly ash handling, upgrading its wastewater treatment systems, and closing coal combustion residuals ponds, all in compliance with numerous recent new and modified EPA rules, for Buckeye's coal-fired units at Cardinal Generating Station in Brilliant, Ohio ("Cardinal").

8. In 2003, selective catalytic reduction (SCR) equipment was placed in commercial operation at Cardinal at a total capital cost of approximately $185 million. In 2008, construction of flue gas desulfurization (FGD) equipment was completed and placed into service on Unit No. 2 at Cardinal. The capital cost of the equipment was approximately $275 million. In 2012, FGD equipment was installed on Unit No. 3 at Cardinal, for a capital cost of approximately $400 million. In 2021, dry fly ash handling equipment was installed at the Cardinal Plant at a capital cost of approximately $60 million.

9. In 2023, the bottom ash handling systems were modified to a closed loop configuration at a capital cost of approximately $30 million. Buckeye expects to close its fly ash

and bottom ash ponds by 2025 at a cost of approximately $80 million. Buckeye is currently in the process of upgrading its FGD wastewater treatment plant to comply with the EPA's 2020 Effluent Limitation Guidelines ("ELG") Rule by 2025 at a capital cost of approximately $30 million. Similar environmental capital investments have been made by the Ohio Valley Electric Corporation ("OVEC") for its two coal-fired power plants, of which Buckeye is an 18% owner and responsible for 18% of its costs.

10. Buckeye remains committed to maintaining a diverse portfolio of generation sources that balances affordability, reliability, and environmental responsibility. Buckeye's generation portfolio includes both fossil fuel-fired and renewable generating resources. In all, Buckeye's portfolio of owned or controlled generation resources includes coal (~1,600 Megawatts ("MW")), natural gas (~700 MW), and renewable energy (~75 MW).

11. Buckeye owns or receives power from numerous electric generating units ("affected EGUs") that are subject to the Rule and thus must comply with the Rule's stringent new standards for steam electric units. These affected EGUs have remaining useful lives that may be significantly shortened under the Rule—all at substantial cost to Buckeye, and ultimately, to the rural consumers who are in Buckeye's service area. The table below identifies the coal-fired EGUs that will be impacted if the Rule takes effect.

Affected EGU	State
Cardinal Units 1 & 2	OH
Clifty Creek Units 1-6	IN

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Kyger Creek Units 1-5	OH

Overview of Final Rule

12. EPA's steam electric ELGs regulate specific wastestreams and pollutants from coal-fired units through binding conditions imposed in a facility's National Pollution Discharge Elimination System (NPDES) permit issued under the Clean Water Act (CWA). EPA establishes nationwide limits for these wastestreams based on the Best Available Technology Economically Achievable (BAT). In general, EPA has determined in the Rule that a suite of zero-discharge treatment systems (membrane filtration and thermal or spray dryer evaporation) are technologically available and economically achievable for the steam electric industry and therefore EPA establishes zero-discharge limits (i.e. zero liquid discharge (ZLD)) for flue gas desulfurization wastewater (FGDW), bottom ash transport water (BATW), and combustion residual leachate (CRL). EPA also establishes more stringent limits for legacy wastewater (LWW) based on a determination that chemical precipitation is BAT for this wastestream.

13. Facilities must meet these limits as soon as possible (ASAP) after July 8, 2024 (but no later than Dec. 31, 2029), unless they retire or repower by December 31, 2034. EPA has determined that given the short remaining useful life of facilities (and associated wastewater treatment equipment) ceasing coal combustion by December 31, 2034, it would be unreasonable to require additional upgrades at these facilities. This is due, in part, to having fewer years over which to amortize the costs of installing new treatment technology. Thus, facilities that retire or repower by December 31, 2034 do not have to meet the no discharge limit for certain wastestreams until after the facility ceases coal combustion but must continue to comply with the limits established by EPA in the 2020 ELG rule.

14. For existing sources that discharge directly to surface water, except for the subcategories discussed below, the final rule establishes the following generally applicable limits based on BAT: no discharge of FGDW based on zero-discharge systems, including membrane filtration systems, spray dryer evaporators (SDEs), and thermal evaporation systems, alone or in any combination, including any necessary pretreatment (e.g., chemical precipitation) or post-treatment (e.g., crystallization); no discharge of BATW based on dry-handling or closed-loop systems, including pneumatic systems, under-boiler mechanical drag system, and submerged grind conveyors; no discharge of CRL based on the same systems evaluated for FGDW. Facilities must meet the new no discharge limits by ASAP after the final rule's effective date but no later than Dec. 31, 2029.

15. For "unmanaged CRL," EPA establishes mercury and arsenic limits based on chemical precipitation treatment technology. EPA defines "unmanaged" CRL in the Rule to mean CRL which either: (1) the permitting authority determines are the functional equivalent of a direct discharge to waters of the United States (WOTUS) through groundwater or (2) CRL that has leached from a waste management unit into the subsurface and mixed with groundwater prior to being captured and pumped to the surface for discharge directly to a WOTUS.

16. Discharges of legacy wastewater from ongoing surface impoundment closures are subject to the permitting authorities best professional judgment (BPJ). Discharges of legacy FGDW, BATW, or CRL from surface impoundments commencing closure after the final rule's effective date are subject to mercury and arsenic limits based on chemical precipitation treatment technology.

17. The Rule retains the final 2020 Rule BAT technology bases and limitations for FGDW and BATW as interim limitations until the applicability dates of the new zero discharge

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limits. The 2020 Rule established BAT limitations for FGDW based on chemical precipitation plus low hydraulic residence time biological treatment. BAT limitations for BATW were based on high recycle rate systems with up to a 10% volumetric purge.

18. The Rule also maintains the 2020 Rule's permanent cessation of coal combustion (PCCC) subcategory (which requires retirement or repowering by December 31, 2028) and the 2020 Rule's voluntary incentive program (VIP) and creates a new subcategory for units permanently ceasing coal combustion by December 31, 2034. Units that qualify for the 2034 PCCC subcategory are subject to the zero discharge limit for FGDW and BATW after Apr. 30, 2035, and subject to mercury and arsenic limits for CRL no later than Apr. 30, 2035. Units seeking to qualify for the 2034 PCCC subcategory must satisfy the 2020 Rule's limits for FGDW *and* BATW no later than December 31, 2025, submit a Notice of Planned Participation (NOPP) by December 31, 2025, and cease coal combustion by December 31, 2034.

Impact of the Final Rule on Buckeye

19. Buckeye relies on the affected EGUs for most of its current generation needs from a capacity perspective (1,600 MW out of 2,400 MW total owned or controlled capacity) and nearly all of its generation needs from an energy perspective (annually greater than 80% of its energy supply). Accordingly, the Rule will have a substantial impact on every aspect of Buckeye's operations. These impacts will ultimately be felt by the consumers in Buckeye's service area – many of whom live in persistent poverty conditions, and all of whom depend on reliable generation to power their homes and keep them warm during frigid winters or cool during scorching summers.

Impacts at Cardinal Station

20. Cardinal Power Plant has two affected EGUs, Units 1 and 2, that generate up to 1,180 MW for use by Buckeye. It is situated on the Ohio River in Brilliant, Ohio, about 50 miles west of Pittsburgh and 15 miles north of Wheeling, West Virginia. Cardinal Unit 1 was placed in commercial service in 1967 and was purchased by Buckeye in 2022, but its output is dedicated to others until 2028, when its output will become available to Buckeye. Cardinal Unit 2 also came on-line in 1967 and is owned by Buckeye and dedicated to its use. Each Unit has generating capacity of 590 MW. Cardinal Unit 3, also owned by Buckeye, began operation in 1977 and has generating capacity of 620 MW, but it is committed to retire in 2028 rather than install the equipment for Unit 3 that would otherwise be required to be in service by 2025 to comply with EPA's 2020 ELG rule. Buckeye's purchase of Unit 1 paved the way for Buckeye to retire Unit 3 by the end of 2028, at which time Buckeye will rely on Cardinal Units 1 and 2 for its needs.

21. Buckeye is contracted to install biological treatment to comply with the 2020 Rule by December 31, 2025. If a stay is not granted, Buckeye will need to undertake additional technology evaluation to determine feasibility and compliance costs of achieving ZLD, at an immediate and irreversible cost, estimated at approximately $1 million, to Buckeye and its members.

22. If Buckeye determines installing technology to satisfy ZLD requirements is viable and cost effective for the Cardinal Units, and can be installed by the compliance deadline, Buckeye will need to be begin spending money immediately to meet the no later than December 31, 2029, compliance deadline. In the meantime, Buckeye must still must install biological treatment to satisfy compliance with the 2020 ELG Rule (not waived by the 2024 ELG Rule), which will then become a stranded asset either because it will be replaced by a ZLD technology

before the end of 2029, or because the units will be required to retire by no later than December 31, 2034 (or 2032 if the EPA Greenhouse Gas (GHG) Rule[1] is upheld).

23. If the Buckeye determines that the installation of ZLD technology at Cardinal is even possible by the December 31, 2029, compliance deadline, Buckeye estimates the cost of compliance with the Rule at Cardinal at approximately $100-130 million, approximately half of which would be spent in the first few years for engineering and material procurement; however, this is a preliminary estimate based on preliminary discussions with potential vendors for the ZLD technology and assumes that the ZLD technology can be achieved at Cardinal and be installed in time.

24. If ZLD is not technologically feasible for the Cardinal Units, or if compliance costs are too high, or if compliance cannot be achieved by the December 31, 2029, compliance deadline, Buckeye will need to retire the Cardinal Units by 2029 (or by 2034 if Buckeye submits a NOPP before the December 31, 2025 deadline , or by 2032 if EPA's GHG Rule is upheld). If retirement is necessary, then Buckeye must begin spending money immediately to identify how to replace the retired power plants, either through the purchase of replacement power or the construction or acquisition of replacement generating assets, as well as either write-off or create and amortize a regulatory asset for power plants committed to retire by a date certain. These are steps that are irreversible (or reversible with exorbitant costs) and would result in large rate increases to Buckeye's customers, all as described in Buckeye's Declaration supporting NRECA's Motion to Stay the EPA GHG Rule, attached as Exhibit A.

[1] *New Source Performance Standards for Greenhouse Gas Emissions From New, Modified, and Reconstructed Fossil Fuel-Fired Electric Generating Units; Emission Guidelines for Greenhouse Gas Emissions from Existing Fossil Fuel-Fired Electric Generating Units; and Repeal of the Affordable Clean Energy Rule*, 89 Fed. Reg. 39798 (May 9, 2024) ("GHG Rule")

25. *Zero discharge may not be achievable at Cardinal*. The Rule allows affected EGUs to remain in operation beyond 2034 only if they can achieve zero discharge of FGDW as soon as possible after July 8, 2024 but no later than December 31, 2029. Installing zero discharge FGDW treatment technology may not be a technically or commercially viable solution for Cardinal, certainly not before 2029. This conclusion is based on Buckeye's understanding of current zero discharge technology applicable to coal units, like Cardinal, with wet FGD scrubbers, from knowledgeable sources such as the Electric Power Research Institute (EPRI) and technology vendors.

26. This conclusion is also based on the complexities of adding even more treatment technologies at Cardinal while still working towards compliance with the 2020 ELG Rule. The final Rule presents multiple options for facilities to employ in order to achieve ZLD of FGD wastewater. Cost-effectiveness calculations performed by EPA show membrane filtration plus a Spray Dry Evaporator is the least-cost compliance option for Cardinal. Capital costs estimated by EPA for Cardinal are approximately $63 million [DCN SE11756A1]. Using operational data, Cardinal received a preliminary estimate from a vendor of $100-130 million for a similar technology installation. In addition to the cost, Cardinal has physical constraints associated with ZLD. To maintain continued compliance, biological treatment, which must be installed by the end of 2025, will need to continue to operate until all of the ZLD equipment is installed by no later than the end of 2029. Space currently utilized for coal storage would need to be repurposed for wastewater treatment.

27. Achieving ZLD on coal plants, like Cardinal, with a wet FGD system is particularly difficult because of the volumes of wastewater generated by a wet FGD system and because of the particular chemistry associated with such wastewater. For this reason, there are no

full-scale installations of the membrane technology on a coal plant, like Cardinal, with wet FGDs. Thus, Cardinal would have to spend over $1 million to perform a technology evaluation and pilot testing just to assess the feasibility of achieving ZLD technology at Cardinal. Absent a stay, this process would need to begin in early 2025. Ironically, under EPA's proposal, Cardinal would, in 2025, be spending money to test the biological treatment system necessary to comply with EPA's 2020 ELG Rule, while, at the same time, spending money to assess the feasibility of installing ZLD technology to comply with EPA's 2024 ELG Rule, which would eventually make Buckeye's investment in the biological treatment system useless.

28. EPA asserts the biological treatment system Buckeye is installing for compliance with the 2020 ELG Rule is not a stranded asset[2]. However, this system will be in operation for no more than four years if Buckeye determines that ZLD technology is technologically and commercially viable for Cardinal and can be installed by 2029. The biological treatment system would be in operation for no more than nine years if Buckeye determines that ZLD technology is not viable for Cardinal, and Buckeye chooses to cease coal combustion by 2034. However, EPA has stated that "all compliance technologies are assumed to have a useful life of 20 years."[3] Under no scenario at Cardinal is this correct.

29. Moreover, if the GHG Rule is upheld, Buckeye will be forced to retire its Cardinal Units even earlier, by 2032 (not 2034). And if the GHG Rule is overturned, Buckeye must, as noted above, either replace by 2029 the 2020 ELG Rule compliance technology with the new technology required by the 2024 ELG Rule, or Buckeye must retire its Cardinal Units by 2034.

[2] p. 1160 Response to Public Comments for Supplemental Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category [DCN SE11794]

[3] p. 3-3 Regulatory Impact Analysis for Revisions to the Effluent Limitation Guidelines and Standards for the Steam Electric Power Generating Point Source Category [EPA 821-R-20-004]

30. *Cessation of coal combustion may be the only option for Cardinal.* If Buckeye determines that the Rule's other purported compliance pathways are not technologically available or economically achievable, Buckeye would have no choice but to submit a NOPP and commit to retire Cardinal Units 1 and 2 before 2034 if the Rule remains in effect during this litigation. Under that compliance option, Buckeye would be permitted to continue to operate its Cardinal Units pursuant to the FGDW limits in the 2020 Rule, and without needing to install additional expensive or unproven technologies or alter operations in a way that would not justify the limited amount of additional time that the units would operate, but Buckeye would be committed to retiring its Cardinal Units by 2034 rather than operating indefinitely, which is what Buckeye would plan to do absent the Rule and the companion GHG Rule.

31. If Buckeye submits a NOPP, Buckeye must immediately begin spending money across several expense categories to replace the power from the Cardinal Units that would be lost in 2034, all as described in Buckeye's GHG Rule Declaration, a copy of which is attached as Exhibit A.

32. Given (a) the substantial new investments required to comply with the Rule, which Buckeye estimates at $100-130 million for Cardinal, and the substantial wasted and stranded investments in 2020 ELG Rule compliance created by the Rule, and (b) the outcome that Buckeye will retire its coal Units by 2032 if the EPA GHG Rule is upheld, then if both the 2024 ELG Rule and the EPA GHG Rule are not stayed, it is likely that Buckeye, which was otherwise planning to operate past 2034, will make the election, provided by the Rule, to submit a NOPP and commit to retire the affected EGUs by the end of 2034. This would allow Buckeye to continue to operate until the end of 2034, rather than the end of 2029, which would be the

longest that affected EGUs would be permitted to operate under the Rule without making substantial new investments and without submitting a NOPP.

33. On the other hand, if Buckeye makes the decision to comply with the Rule while it and the GHG Rule are under appeal for the next several years, it would need to start spending money immediately on the investments required to comply with the ELG Rule by its no later than 2029 compliance date, and thereby risk having those investments become uneconomic and stranded investments if EPA's GHG Rule is not overturned. As mentioned above, it's unlikely that Buckeye would take the risk of stranding valuable assets and would, instead, likely submit a NOPP and commit to ceasing coal combustion (unless both this Rule and the GHG Rule are stayed while this litigation is pending).

34. EPA finalized the Rule at the same time as the GHG Rule, as part of a coordinated and inter-related suite of four new rules affecting power plant air emissions, water discharges, and solid waste disposal.

35. Without having both the Rule and the GHG Rule stayed, Buckeye, which was otherwise planning to operate after 2034, will be faced with the prospect of attempting to make environmental expenditures to comply with the Rule, with no assurance that such expenditures will not become stranded in 2032 should the GHG Rule be upheld, or making a retirement commitment by submitting a NOPP by the end of 2025, even if Buckeye would have otherwise been willing to make the investments in ELG compliance to operate past 2029 and 2034 should the GHG Rule ultimately be overturned.

36. In Buckeye's opinion, the combined effect of the Rule and the GHG Rule is designed to pressure affected EGUs to make binding commitments to retire, whether by 2025 under the Rule, and/or by 2026 under the GHG Rule, by forcing the affected EGUs to face the

prospect of having to make uneconomic or technically impossible investments required under the rules, should the rules ultimately be upheld, while at the same time offering relief from the rules (to the end of 2031 in the case of the GHG Rule, and to 2034 in the case of the Rule) but only if binding commitments to retire are made during the limited window of time while the rules are still under appeal and regulatory uncertainty prevails. For this reason, and given the combined effect of the two rules, issued at the same time by EPA and as part of a package of four power plant rules, it is imperative that both the Rule and the GHG Rule be stayed.

Impacts at Clifty Creek and Kyger Creek

37. As mentioned above, Buckeye is a minority (18%) co-owner of two generation facilities that are operated by OVEC. The Clifty Creek facility has six affected coal-fired EGUs, and the Kyger Creek facility has five affected coal-fired EGUs. As a result of its minority ownership and contractual rights to power, Buckeye receives approximately 400 MW of electricity from these two facilities.

38. Decisions about compliance at these facilities are not solely Buckeye's to make, and instead must be made by OVEC's Board of Directors and its management. Decision-making about the compliance plans for Clifty Creek and Kyger is still in process. Even so, and for many of the same reasons discussed herein with regard to the Cardinal Units, it is likely that, should the Rule and the GHG Rule not both be stayed, OVEC will also make the decision to submit a NOPP and retire its units by the end of 2034 as a result of the Rule, and regardless, each of the available compliance pathways under the Rule would require Buckeye to immediately begin incurring substantial expenses from OVEC as it responds to the Rule (and the GHG Rule) and evaluates compliance alternatives and potential retirement commitments that must be made as soon as 2025.

39. If these facilities find it possible to comply with and decide to comply with the limits in the Rule, OVEC would need to begin making immediate plans and expenditures, such as engineering and procurement, to assure that zero discharge technologies would be in service before 2029. That would create immediate expenses for Buckeye. Yet if these facilities select to cease coal combustion by 2034, then Buckeye would need to begin making immediate expenditures related to securing 400 MW of replacement power, whether that be from the market or from new owned or controlled generation, as discussed in more detail in Buckeye's Declaration Supporting NRECA's Motion to Stay the GHG Rule.

Absent a Stay, Buckeye Will Suffer Immediate Irreparable Harm

40. *Immediate ZLD Technology Evaluation Costs*. If the Rule is not stayed, Buckeye will be forced to immediately spend money evaluating whether the ZLD technology required by the Rule is technologically viable for Cardinal, makes economic sense, and can be installed no later than the December 31, 2029 compliance deadline. These costs are immediate and irreversible and estimated at approximately $1 million for Cardinal.

41. *Immediate ZLD Technology Installation Costs.* If Buckeye determines that ZLD technology is viable, Buckeye will need to begin spending money immediately to meet the no later than December 31, 2029 compliance deadline. Buckeye estimates that approximately 50% of the estimated $100-130 million compliance cost would be spent in 2025 and 2026 for engineering and equipment procurement. However, these investments risk becoming stranded should the GHG Rule not be overturned, as Buckeye would be forced to retire its units by 2032 under the GHG Rule. For this reason, if both the GHG Rule and this Rule are not stayed, it is likely that Buckeye's affected EGUs will submit a NOPP in 2025 and commit to retire in 2034

rather than risk making an expensive and ultimately stranded investment to comply with the 2024 ELG Rule should the GHG Rule not be overturned.

42. *Immediate Replacement Power Costs.* If Buckeye submits a NOPP and commits to retire its Cardinal Units by 2034, Buckeye will need to immediately begin spending money on portfolio modelling to determine how best to replace these assets. Depending on results of that decision, Buckeye would need to begin spending money immediately to construct or acquire replacement generation or purchased power. Buckeye would also need to immediately expense the unamortized investments in Cardinal or create and amortize regulatory assets, all of which will result in rate increases to the Buckeye members.

43. *Stranded Costs Associated with 2020 ELG Compliance.* As described above, under any possible scenario, Buckeye's investments in 2020 ELG compliance, necessary to operate past 2025, will become stranded assets no later than 2034 (if Buckeye submits a NOPP and the GHG Rule is overturned), possibly by 2032 if the EPA GHG Rule is not overturned and Buckeye does not chose to investment in ZLD technology, and as early as 2029 if Buckeye elects to install ZLD technology by the 2029 compliance date in the Rule.

44. *Likely Selection of Binding Retirement Commitment.* If both the GHG rule and the 2024 ELG Rule are not stayed, Buckeye is likely to submit a NOPP in 2025 and commit to cease coal combustion before the end of 2034, given the risks in even attempting to comply with the Rule by installing ZLD technology, since Buckeye would retire by 2032 under the GHG Rule if it is not overturned, i.e. an investment in ZLD technology at an expected cost of $100-130 million would not be economic if amortized over only two years (2030 and 2031 years only). This appears to Buckeye to be EPA's plan in promulgating and issuing both the 2024 ELG Rule and the GHG Rule at the same time.

45. *These costs are not reversible*. Equipment generally cannot be returned without cost. Dollars spent on portfolio modeling, technology evaluation, generating facility design, planning, permitting, engineering, site selection and acquisition, fuel procurement, financing, replacement power contracts, and other studies and costs cannot be refunded. Legally binding retirement promises generally cannot be undone. Buckeye might even be forced into a retirement decision earlier than what is required under the Rule, if a major capital expenditure at Cardinal is required that could not be justified given the short remaining useful life of Cardinal should Buckeye issue the NOPP and commit to retire Cardinal in 2034 or should the EPA GHG Rule not be overturned and Buckeye be forced to retire Cardinal by 2032.

46. Moreover, these costs cannot be deferred or delayed until the courts reach a final determination on the merits of this litigation. Optimistically, Buckeye expects that process to take *at least* 2-3 years. But the Rule's compliance deadlines do not give Buckeye any time to spare. On the contrary, time is of the essence, unless the Rule is stayed.

47. In sum, if the Rule remains in effect while this litigation is pending, Buckeye will have no choice but to incur significant unrecoverable compliance costs as well as to shoulder the many other substantial, immediate, and irreparable harms described above.

I declare under penalty of perjury under the laws of the United States of America, pursuant to 28 U.S.C. § 1746, that the foregoing is true and correct to the best of my knowledge.

Executed on this 23rd day of July, 2024, in Columbus, Ohio.

Craig Grooms

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EXHIBIT A

BUCKEYE'S DECLARATION SUPPORTING
NRECA'S MOTION TO STAY THE EPA GREENHOUSE GAS RULE

Appellate Case: 24-2123 Page: 19 Date Filed: 07/26/2024 Entry ID: 5417837

DECLARATION OF CRAIG GROOMS

I, Craig Grooms, declare as follows:

1. My name is Craig Grooms. I am the Chief Operating Officer at Buckeye Power, Inc. ("Buckeye"). I am over the age of 18 years, and I am competent to testify concerning the matters in this declaration. I have personal knowledge of the facts set forth in this declaration, and if called and sworn as a witness, could and would competently testify to them.

2. I have almost three decades of experience in electricity generation, and I have been employed at Buckeye since 2004. I hold a Bachelor of Science degree in Electronic Engineering Technology from the University of Dayton, as well as a Master of Business Administration degree from Otterbein University. As Chief Operating Officer at Buckeye, I am responsible for the management and direction of Buckeye's engineering and operations functions, including power delivery, engineering, information technology and resources, and market operations.

3. Buckeye is a member of the National Rural Electric Cooperative Association ("NRECA") and is also a member of America's Power. This

declaration is submitted in support of the litigation challenging EPA's final rule entitled *New Source Performance Standards for Greenhouse Gas Emissions From New, Modified, and Reconstructed Fossil Fuel-Fired Electric Generating Units; Emission Guidelines for Greenhouse Gas Emissions from Existing Fossil Fuel-Fired Electric Generating Units; and Repeal of the Affordable Clean Energy Rule*, 89 Fed. Reg. 39798 (May 9, 2024) (the "Final Rule" or "Rule").

4. I am familiar with Buckeye's operations, including generation and transmission, regulatory compliance, workforce management, and electric markets in general. I also am familiar with the Final Rule, and I am familiar with how the Final Rule will affect Buckeye as well as its suppliers, members, consumers, and employees.

5. Buckeye is an Ohio non-profit corporation operating according to a cooperative business model. Buckeye commenced commercial operations in 1959 and provides wholesale electric service to its 25 members, which includes all electric distribution cooperatives engaged in the sale of electricity within the state of Ohio. The retail service area of Buckeye's members covers a substantial part of the land area of the state of Ohio and

extends into portions of 77 of Ohio's 88 counties. Buckeye's members currently serve approximately 400,000 consumers, 91% of whom are classified as residential (farm and nonfarm).

6. Buckeye is fully committed to environmental stewardship. In recent years, Buckeye has spent **well over $1 billion** installing state-of-the-art, high-performing selective catalytic reduction and jet bubbling reactor flue gas desulfurization equipment, as well as converting from wet to dry fly ash handling, upgrading its wastewater treatment systems, and closing coal combustion residuals ponds, all in compliance with numerous recent new and modified EPA rules, for Buckeye's coal-fired units at Cardinal Generating Station in Brilliant, Ohio ("Cardinal").

7. In 2003, selective catalytic reduction (SCR) equipment was placed in commercial operation at Cardinal at a total capital cost of approximately $185 million. In 2008, construction of flue gas desulfurization (FGD) equipment was completed and placed into service on Unit No. 2 at Cardinal. The capital cost of the equipment was approximately $275 million. In 2012, FGD equipment was installed on Unit No. 3 at Cardinal, for a capital

cost of approximately $400 million. In 2021, dry fly ash handling equipment was installed at the Cardinal Plant at a capital cost of approximately $60 million.

8. In 2023, the bottom ash handling systems were modified to a closed loop configuration at a capital cost of approximately $30 million. Buckeye expects to close its fly ash and bottom ash ponds by 2025 at a cost of approximately $80 million. Buckeye is currently in the process of upgrading its flue gas desulfurization wastewater treatment plant to comply with the EPA's 2020 Effluent Limitation Guidelines ("ELG") by 2025 at a capital cost of approximately $30 million. Similar environmental capital investments have been made by the Ohio Valley Electric Corporation ("OVEC") for its two coal-fired power plants, of which Buckeye is an 18% owner and responsible for 18% of its costs.

9. Buckeye remains committed to maintaining a diverse portfolio of generation sources that balances affordability, reliability, and environmental responsibility. Buckeye's generation portfolio includes both fossil fuel-fired and renewable generating resources. In all, Buckeye's

portfolio of owned or controlled generation resources includes coal (≈1,600 Megawatts ("MW")), natural gas (≈700 MW), and renewable energy (≈75 MW).

10. Buckeye owns or receives power from numerous electric generating units ("affected EGUs") that fall within the Final Rule's ambit and thus must comply with the Final Rule's stringent new standards for coal-fired steam units. These affected EGUs have remaining useful lives that will be significantly shortened under the Final Rule—all at substantial cost to Buckeye, and ultimately, to the rural consumers who are in Buckeye's service area. The table below identifies the coal-fired EGUs that will be impacted if the Final Rule takes effect, as well as Buckeye's current strategy to comply with the Final Rule and the approximate costs to Buckeye of that compliance strategy.[1]

[1] Buckeye is also the owner of approximately 700 MW of peaking gas-fired generation resources. Given the current annual capacity factors of these resources at less than 20%, Buckeye does not expect additional compliance strategies to be necessary for these resources as a result of the Final Rule.

Affected EGUs	State	Compliance Strategy	≈Cost to Buckeye[2]
Cardinal Units 1-2	OH	Retire before 2032, to claim Applicability Exemption	$800 million to $1.3 billion
Cardinal Unit 3	OH	Retirement already scheduled for 2028.	NA
Clifty Creek Units 1-6	IN	Compliance strategy to be determined by OVEC[3]	$25-100 million if compliance strategy is retire before 2032
Kyger Creek Units 1-5	OH	Compliance strategy to be determined by OVEC	$25-100 million if compliance strategy is retire before 2032

OVERVIEW OF THE FINAL RULE

11. The Final Rule sets CO_2 emissions limits that States must apply to existing coal-fired steam units, under Section 111(d). 89 Fed. Reg. at 39840. The Rule also sets CO_2 emissions limits for new gas-fired combustion-turbine units, under Section 111(b). *Id.* at 39902. Both existing and new units

[2] Assuming that all 1,600 MW of replacement power is purchased from the PJM market during the period 2032 to 2040 and based on the difference between (a) expected forward prices for energy, plus capacity clearing prices of $100/MW-day to $250/MW-day, in the PJM market, and (b) the expected costs to operate the Cardinal and OVEC EGUs during that same period.

[3] Clifty Creek and Kyger Creek Power Plants are owned by OVEC of which Buckeye owns an 18% interest. Buckeye is also entitled to 18% of the power output from the Clifty Creek and Kyger Creek coal-fired units.

must meet emissions limits equal to what EPA says 90% carbon-capture-and-sequestration can achieve. Existing units that cannot achieve this must shut down. New units that cannot achieve this must drastically reduce their output of electricity.

12. *Existing coal-fired units.* The Rule divides existing coal-fired steam units into three non-overlapping subsets: two are "subcategories" and one is an "applicability exemption." *Id.* at 39841. These subsets are defined by whether a unit has committed to permanently retire, and by the retirement date that a unit has committed to. *See id.* To be effective, these commitments must be included in State plans, which are due to EPA in 24 months. *Id.* at 39874. If a unit does not commit to retire, it is placed into the first subcategory by default. *See id.* at 39841.

13. The first subcategory is for "long-term" units, which EPA defines as units that plan to operate on or after January 1, 2039. *Id.* at 39801. EPA says that the best system for these units is CCS that captures 90% of the CO_2 from a unit. *Id.* at 39845. The first part of this "system" is the design and installation of CCS technology. *Id.* at 39846. After that, the captured CO_2

must be transported (usually via pipeline) to a sequestration site that can permanently store it (usually underground). *See id.* EPA "assumes" that "work" toward "each component of CCS" will begin in June 2024, *id.* at 39874, and the Rule requires that work to be completed before January 1, 2032, *id.* at 39801.

14. The second subcategory is for "medium term" units: those that make a federally enforceable commitment to "permanently cease operation before January 1, 2039." *Id.* EPA's best system for this subcategory is "co-firing with natural gas[] at a level of 40 percent "—*i.e.*, transforming a coal unit into one that combusts both coal and natural gas. *Id.* EPA assumes that medium-term units will begin compliance work in June 2024, and the Rule requires those units to reach full compliance by January 1, 2030. *Id.* at 39893.

15. Third, units that make a federally enforceable commitment to permanently cease operating before January 1, 2032, have an "applicability exemption" and are not subject to the Rule. *Id.* at 39801. But "[i]f a source continues to operate past this date, it is no longer exempt," and is thus in violation of the state plan and the Clean Air Act. *Id.* at 39843; *see id.* at 39991.

16. *New gas-fired combustion turbine units*. For new and modified gas-fired combustion turbines, the Rule creates three subcategories. These subcategories are defined by a unit's "electric sales (*i.e.*, utilization) relative to the [unit's] potential electric output." *Id.* at 39908.

17. "Low load" units (those that sell "20 percent or less of their potential electric output") must comply with a standard of performance based on "lower-emitting fuels." *Id.* at 39917. "Intermediate load" units (those that sell 20-40% of their potential electric output) must comply with a standard based on "high-efficiency simple cycle turbine technology." *Id.* "Base load" units are those that supply greater than 40 percent of their potential electric output as net-electric sales. *Id.* These units must immediately comply with a multi-phase standard of performance. Phase I is based on highly efficient combined-cycle generation. *Id.* Phase II is based on 90% capture of CO_2 using CCS by January 1, 2032 (and is cumulative of Phase I). *Id.* Phase II requires units only to meet a stringent standard of performance, not to use any particular technology.

IMPACT OF THE FINAL RULE ON BUCKEYE

18. Buckeye relies on affected coal-fired EGUs for most of its current generation needs from a capacity perspective (1,600 MW out of 2,400 MW total owned or controlled capacity) and nearly all of its generation needs from an energy perspective (annually greater than 80% of its energy supply). Accordingly, the Final Rule will have a substantial impact on every aspect of Buckeye's operations. These impacts will ultimately be felt by the consumers in Buckeye's service area—many of whom live in persistent poverty conditions, and all of whom depend on reliable generation to power their homes and keep them warm during frigid winters.

I. Impacts at Cardinal Station — "Imminent" Retirement

19. Cardinal Power Plant has two affected EGUs, Units 1 and 2, that generate up to 1,180 MW for use by Buckeye. It is situated on the Ohio River in Brilliant, Ohio, about 50 miles west of Pittsburgh and 15 miles north of Wheeling, West Virginia. Cardinal Unit 1 was placed in commercial service in 1967 and was purchased by Buckeye in 2022, but its output is dedicated to others until 2028, when its output will become available to Buckeye. Cardinal Unit 2 also came on-line in 1967 and is owned by Buckeye and

dedicated to its use. Each Unit has generating capacity of 590 MW. Cardinal Unit 3, also owned by Buckeye, began operation in 1977 and has generating capacity of 620 MW, but it is committed to retire in 2028 rather than install the equipment for Unit 3 that would otherwise be required to be in service by 2025 to comply with EPA's 2020 ELG rule. Buckeye's purchase of Unit 1 paved the way for Buckeye to retire Unit 3 by the end of 2028, at which time Buckeye will rely on Cardinal Units 1 and 2 for its needs.

20. Unit 1's remaining depreciable life is indefinite, as Buckeye depreciates Cardinal assets based on an annual composite depreciation rate of 4% as capital assets are placed in service. Depreciable life is an accounting metric for allocating costs, not a measure of how long a plant can reasonably be expected to remain useful. No specific retirement date has been set for the Cardinal Units, other than Unit 3, which will retire no later than December 31, 2028. Likewise, Unit 2 has a long horizon of remaining useful life without a set retirement date for depreciation or any other purpose. With nearly 300 employees, and scores of vendors and contractors supporting them, Cardinal is a major economic force in the region. Because of those and other

factors, Buckeye had planned to keep Unit 1 and Unit 2 operating indefinitely and as long as physically and economically viable. Yet, because of the Final Rule, Buckeye now plans to retire these units before 2032, and believes that it is likely that OVEC will make a similar determination with respect to its units, of which Buckeye has an 18% interest and 400 MW entitlement.

21. *CCS is not achievable at Cardinal*. The Final Rule allows affected EGUs to remain in operation beyond 2038 only if they can achieve 90% CCS before 2032. CCS is not a technically or commercially viable solution for Cardinal, certainly not before 2032. This conclusion is based on Buckeye's understanding of current CCS technology from knowledgeable sources such as the Electric Power Research Institute (EPRI)[4]. This conclusion is also based on the problems involved in even considering CCS for Cardinal, including

[4] See EPRI Comments on EPA's proposed greenhouse gas rule for power plants, dated August, 2023, filed in Docket ID: EPA-HQ-OAR-2023-0072 (the "Proposed Rule"), at page 4. "The power industry's experience with full-scale construction, deployment, and operation of CCS technology is nascent. A phased approach to CCS deployment is needed to allow further demonstrations in order to answer key questions around costs, development, and operation prior to industry-level deployment."

lack of available storage sites for CO_2, costs and permitting timelines for CO_2 storage, pipelines to transport captured CO_2 from Cardinal to storage sites (even assuming such sites are available), the amount of Cardinal generation output that would be required to power CCS equipment at Cardinal (thereby reducing overall Cardinal plant efficiency and net output), and the strict requirement under the Final Rule to capture 90% of Cardinal's CO_2 emissions—a requirement that has not been demonstrated anywhere.

22. Buckeye understands that one of the only CCS projects currently proposed for a coal-fired power plant, *i.e.* Project Tundra at Young Station in North Dakota, would not meet the 90% carbon capture rate required by the Final Rule, and this is for a coal-fired power plant much smaller than Cardinal. Buckeye will continue to monitor the status of CCS technology, but right now the technology remains in a nascent and experimental state that is not technically or commercially viable for Cardinal. Furthermore, even if CCS were a technically and commercially viable compliance strategy for Cardinal, permitting, siting, design, and construction standards for CCS—including for CO_2 storage and CO_2 pipeline transportation from Cardinal to

storage, as well as the CO_2 capture technology itself—mean that any such CCS system could not be placed into service by the January 1, 2032, compliance date required by the Final Rule.

23. *Natural gas co-firing is not achievable at Cardinal*. The Final Rule allows affected EGUs to remain in operation beyond 2038 only if they begin co-firing with 40% natural gas by January 1, 2030. Given the costs and time necessary to extend natural gas supplies to Cardinal, the inefficiencies of the older Cardinal cycle design as compared to modern, efficient gas combined cycle plants already in service or planned to be in service, and given the limited time that natural gas co-firing would be allowed under the Final Rule (only through 2038), the Medium Term compliance strategy is not a commercially viable option for Buckeye.

24. Buckeye has contacted two nearby interstate gas pipelines, one 6 miles distant and the other 33 miles distant, and has estimated the cost to extend gas supplies from such interstate pipelines to Cardinal as between $100-200 million dollars, as well as requiring a firm commitment from Buckeye to purchase gas transportation services for 20-25 years in order for

the pipeline company to amortize the cost of the new pipeline lateral through rates charged to Buckeye. Such a long-term commitment makes little sense given that Cardinal would be forced to retire Cardinal by the end of 2038 under the Final Rule, far short of the full 20-25 year purchase commitment that would be required from the pipeline company.

25. Furthermore, even if this option were commercially viable, it may not be practically possible by January 1, 2030, given the time needed to permit and install pipeline laterals to Cardinal from the nearby interstate gas pipelines, which Buckeye understands would take a minimum of 5 years to permit. Buckeye is also exploring whether unprocessed gas from local wells would be available from local intra-state gathering pipelines, rather than from interstate gas pipelines, but Buckeye has not confirmed that any such gas would be available in sufficient quantities or of a sufficient quality to support co-firing at Cardinal or what regulatory and permitting requirements would apply to such arrangements, as compared to purchases of processed gas from interstate pipeline.

26. *Imminent retirement is the only option for Cardinal*. Because the Final Rule's other purported compliance pathways are not demonstrated and are not commercially viable, Buckeye would have no choice but to retire Cardinal Units 1 and 2 before 2032 if the Final Rule remains in effect during this litigation. Under that compliance option, Buckeye would be permitted to continue to operate its Cardinal Units through the end of 2031 under current carbon emission rates, and without needing to install expensive or unavailable technologies or alter operations in a way that would not justify the limited amount of additional time that the units would be permitted to operate with such technologies or changed operations in place.

27. To meet the Final Rule's deadline for these retirements, Buckeye must immediately begin spending money across several expense categories.

28. *Replacement power costs*. Buckeye must replace approximately 1,180 MW of power (1,600 MW including OVEC) that will disappear by the end of 2031 as a result of the Final Rule's forced shut-down requirement for Cardinal Units 1 and 2. But Buckeye still must continue to provide power to its members. That will require either buying new power from the market

and/or building new generation. Based on current expected market prices for power during the period 2032 to 2040 (a period of just 8 years), as compared to the expected costs of continuing to produce power from the Cardinal Units during that same period, replacing the Cardinal Units with market power for just eight years will cost approximately **$800 million to $1.3 billion ($850 million to $1.5 billion including Buckeye's share of OVEC)**—all costs that would ultimately be borne by the consumers in Buckeye's area.

29. Yet these assumptions reflect only *current* market dynamics. They are very likely to change for the worse once EGUs across the region and the Nation are contemporaneously turning to the market for replacement power and are turning to equipment manufacturers for new equipment because of the impacts of the Final Rule on all affected EGUs, not just Buckeye's.

30. If the Final Rule takes effect, electric markets will be highly constrained, as generators across the country will see reductions in their portfolios. Coal-fired power plants currently produce about 20% of the

United States electric supply that will almost certainly be entirely eliminated by 2032 under the Final Rule due to its unrealistic and unavailable compliance options. Depending on the results of portfolio modelling and other studies that Buckeye will conduct now that the Final Rule has been issued, Buckeye may need to construct at least some new generation to replace the generation to be retired under the Final Rule.

31. Yet the Final Rule also imposes stringent requirements for new baseload EGUs—all of which must achieve 90% CCS by January 1, 2032. That level of CCS and the compliance timeline is not technically or economically viable for new coal or gas-fired baseload EGUs based on Buckeye's current understanding of CCS technology.

32. Nor can Buckeye depend solely on renewables and battery backups for baseload generation. To attempt to provide replacement generation for the vast baseload power that Buckeye will lose under the Final Rule, and given the problems with renewable generation associated with its intermittent and non-dispatchable (*i.e.*, non-controllable) nature, and the inability to construct new baseload (*i.e.*, high capacity factor) generation that

is gas or coal under the Final Rule without the installation of unproven and experimental CCS technology, the only technically viable option under the Final Rule to replace baseload, dispatchable coal-fired generation (apart from nuclear) is to use a large number of low-capacity factor simple-cycle combustion turbines (CTs) all running at a capacity factor of 20% or less[5], or a more expensive combined-cycle plant limited to a 40% capacity factor[6], and all depending on a fuel supply (gas) that is subject to high price volatility and limits on availability in the winter months, together with market purchases and/or renewables during the many hours that CTs would not be permitted to run given their low capacity factors. Low-capacity factor gas peaking generators combined with market purchases and/or renewables are in no way an adequate or equivalent replacement generation resource for

[5] The expected capital cost of 1,600 MW of gas-fired simple-cycle CTs in PJM is $1.5 billion by itself at an estimated cost of $925/kW (as determined by PJM in a 2022 study), which does not include the additional cost of market purchases and/or renewables needed during the hours when the CTs can't run, nor does it include the cost of fuel, maintenance, repairs, etc. to run the CT's .

[6] The expected capital cost of 1,600 MW of gas-fired combined-cycle CTs in PJM is $1.9 billion by itself at an estimated cost of $1,195/kW (as determined by PJM in the same 2022 study).

high capacity factor, dispatchable, load-following, baseload generation resources like Cardinal. Furthermore, for replacement generation to be available before 2032, Buckeye must begin spending money now for planning, design, siting, permitting, financing, equipment and fuel procurement, and construction. While nuclear is an option, its high initial capital costs, history of cost overruns, and long lead times for construction don't make it a viable replacement generation option if required to be placed in service before 2032 as the Final Rule requires.

33. In addition, prior to building or acquiring replacement peaking resources, Buckeye must begin spending money now for portfolio modelling and other studies so that the appropriate balance between replacement generation, market purchases, financial and fuel hedging, and other arrangements can be developed. This type of portfolio modelling would be a precursor to any definitive steps to obtain replacement generation resources.

34. Given the likely retirement of all or near all coal-fired baseload EGUs before 2032 under the Final Rule, the inability of new coal and gas-

fired baseload resources to be constructed so as to meet a 90% CCS by January 1, 2032, and the time required to design, plan, permit, site, finance and construct even intermittent renewables and low capacity factor simple-cycle CTs under normal conditions, let alone under conditions where a large part of the current generation fleet all needs to be replaced at the same time with the same type of replacement resources from the same vendors and service providers, and where electric demand is increasing rapidly as a result of the electrification of the economy, including in the transportation sector through increasing use of electric vehicles, and because of the rapidly increasing requirements of data centers for electric service to support artificial intelligence and cryptocurrency mining, reliability constraints and higher prices for electricity seem likely if the Final Rule is allowed to go into effect. Nearly every knowledgeable industry participant with an interest in maintaining a reliable electric system including the North American Electric Reliability Corp, the PJM Interconnection, the Mid-Continent Independent System Operator, the Electric Power Research Institute, and NRECA itself,

along with members of Congress from both political parties, have expressed similar concerns regarding the proposed and now Final Rule.[7]

35. *Stranded costs*. The depreciable lives of Cardinal Units 1 and 2 are currently indefinite, as capital assets at Cardinal are depreciated as they are incurred under an annual composite depreciation rate of 4%.

[7] *See* EPRI Comments on the Proposed Rule ("The combined effects of the proposed rules would impact approximately 40% of total U.S. dispatchable power generation capacity. To maintain reliability through the clean energy transition, the power sector would need to address the resulting dispatchable generation impact with similarly flexible resources. Phased approaches that involve full-scale demonstrations prior to widespread deployment are critical to a reliable and affordable transition."); NRECA Comments on the Proposed Rule filed August 8, 2023 (stating that the early retirements caused by the Rule "will pose direct threats to electric grid reliability that EPA fails to appropriately assess and inaccurately models."); Joint Comments of Electric Reliability Council of Texas, Inc.; Midcontinent Independent System Operator, Inc.; PJM Interconnection, L.L.C.; and Southwest Power Pool, Inc. to the Proposed Rule filed August 8, 2023 ("Without firm proof of the commercial and operational viability of these technologies [CCS and hydrogen cofiring], proceeding with these requirements could place the reliability of the electric grid in jeopardy."); Comments dated August 1, 2023 filed by 39 U.S. Senators on the Proposed Rule; and Comments filed June 9, 2023 and December 20, 2023 by U.S. Senator Joe Manchin III on the Proposed Rule. While NERC did not file comments on the Proposed Rule, NERC's "2023 Long-Term Reliability Assessment," published December 2023, emphasized the negative impact the Proposed Rule may have on reliability.

36. As soon as Buckeye is required to make a binding commitment to retire these units, which, under the Final Rule, is 2026 (24 months after the Final Rule goes into effect), then, under accounting rules, these units will no longer be able to be listed as plant in service or to be depreciated on Buckeye's books. Instead, Buckeye will be required in 2026 to immediately expense the remaining book value of these units or to create a regulatory asset. If the remaining book value is immediately expensed, this will result in a massive rate increase to the Buckeye members in that single year. For example, the expected book value of Cardinal Unit 2 alone at 2026 is $380 million. If this amount were to be immediately expensed this would represent a rate increase of 44% in that year as compared to current financial forecast of rates for that year.

37. Even if a regulatory asset is created and amortized through the expected remaining operating life of the units through the end of 2031, this will still result in an increase in Buckeye's rates during that period as compared to what would occur without the Final Rule. Based on forecasted rates for the period through 2031, if the regulatory asset for just Cardinal

Unit 2 were amortized over the period 2026 to 2031, this would result in an expected rate increase of 6% for each year from 2026 through 2031.

38. If, instead, Buckeye chooses to create and amortize the regulatory asset in 2032 or beyond, this will result in stranded costs and increased rates to the Buckeye members. That is because, after the end of 2031, Buckeye will be amortizing and expensing a regulatory asset after the associated units are no longer in service or available to supply power to Buckeye and its members. But, at the same time Buckeye will be required to acquire replacement power after 2031, whether from the market or through construction or acquisition of new generation resources, to replace the retired assets, meaning that, after 2031, Buckeye and its members will be paying both for the cost of replacement power and the remaining unamortized costs of Cardinal Units 1 and 2.

39. Buckeye will also incur additional stranded costs in the form of new and replacement equipment costs at Cardinal Units 1 and 2 placed into service after 2026 that would ordinarily be capitalized under an annual 4% composite depreciation rate if no firm retirement commitment were made,

but would, as a result of the Final Rule, after 2026 be required to be immediately expensed or turned into a regulatory asset as a result of the Final Rule. As mentioned above, if these costs are immediately expensed, that will result in large rate increases to the Buckeye members in the year the costs are expensed, and if, instead, the regulatory asset is amortized through 2031, this will also result in rate increases to the Buckeye members for the years through 2031. If the regulatory asset is amortized past 2031, this will result in a stranded asset and double costs to the Buckeye members for the years after 2031, including both replacement power costs and the unamortized costs of replacements or additions to Cardinal Units 1 and 2.

40. Finally, the Final Rule could result in the retirement of Cardinal Units 1 and 2 long before 2032, even before any appeals of the Final Rule are completed. If any unexpected new or replacement capital asset is required to be placed in service prior to 2032, Buckeye may be forced to retire the Cardinal Units rather than to make the capital expenditure if the cost of the capital expenditure can no longer be justified based on the shorter remaining operating life of the Cardinal Units resulting from the Final Rule as

compared to expected cost of power from the market during the same period. It is unknown when a Cardinal Unit may be required to make a new or replacement capital expenditure as a result of a failure of equipment, accident, or even other EPA rules, such as the 2024 ELG Rule (discussed below). Such retirement decisions are almost always irreversible once made, and certainly not without massive amounts of time and money spent changing course.

41. EPA finalized the new 2024 ELG Rule at the same time as the power plant greenhouse gas emissions Final Rule, as part of a coordinated and inter-related suite of four new rules affecting power plant air emissions, water discharges, and solid waste disposal. Buckeye is currently in the process of spending approximately $30 million to install facilities by 2025 to comply with the EPA's 2020 ELG Rule. The 2024 ELG Rule requires that facilities be installed by 2029 that are completely new and different from those required for 2020 ELG Rule compliance, making the 2020 ELG investments wasted and stranded investments. The 2024 ELG Rule provides an option for affected EGUs to make an election by no later than the end of

2025 to commit, through the issuance of a Notice of Planned Participation (NOPP), to retire their EGUs by the end of 2034. Importantly, if such a commitment is made, the affected EGU will not have to comply with the new mandates in the 2024 ELG rule, so long as the EGU complies by 2025 with the requirements of the 2020 ELG Rule, which 2020 ELG Rule investments are already underway in the case of Cardinal.

42. Given the substantial new investments required to be made by the 2024 ELG Rule[8], which may not be placed into service until as late as 2029, and the substantial wasted and stranded investments in 2020 ELG Rule compliance created by the 2024 ELG Rule, then if the 2024 ELG Rule is not stayed (or if the greenhouse gas Final Rule is not stayed and otherwise fully adjudicated and overturned by the end of 2025), it is likely that Buckeye and many other affected EGUs otherwise planning to operate past 2034 will make the election, provided by the 2024 ELG Rule, to issue a NOPP and commit to retire the affected EGUs by the end of 2034 so as to allow such

[8] Buckeye estimates the cost of 2024 ELG Rule compliance at Cardinal at approximately $70-100 million.

EGUs to operate at least until the end of 2031 (and perhaps a year longer) as permitted under the greenhouse gas Final Rule, rather than the end of 2029, which would be the longest that affected EGUs would be permitted to operate under the 2024 ELG Rule without making the substantial new investments required by such rule.

43. On the other hand, if Buckeye or any other affected EGU makes the decision to comply with the 2024 ELG Rule while it and the greenhouse gas Final Rule are under appeal for the next several years, the EGU would need to start spending money immediately on the investments required to comply with the 2024 ELG Rule by its 2029 compliance date, and thereby risk having those investments become uneconomic and stranded investments if the greenhouse gas Final Rule is not overturned and its effective 2031 retirement date thereby maintained.

44. In sum, without having the greenhouse gas Final Rule stayed and fully adjudicated and overturned by the end of 2025 (or the 2024 ELG rule also stayed), Buckeye and many other affected EGUs otherwise planning to operate after 2034 will be faced with the prospect of making an

uneconomic environmental expenditure (uneconomic because of the shortened life of the Cardinal Units resulting from the Final Rule) to comply with the 2024 ELG Rule, or making a retirement commitment through the issuance of a NOPP by the end of 2025 (earlier than the retirement commitment required under the greenhouse gas Final Rule, which is in 2026), with no assurance that such NOPP retirement commitment would not remain binding, or that compliance with the 2024 ELG rule by 2029 would even be possible, if the Final Rule were ultimately overturned at the end of the litigation process.

45. In Buckeye's opinion, the combined effect of the Final Rule and the 2024 ELG Rule is designed to pressure affected EGUs to make binding commitments to retire, whether by 2025 under the 2024 ELG Rule, and/or by 2026 under the greenhouse gas Final Rule, by forcing the affected EGUs to face the prospect of having to make uneconomic or technically impossible investments required under the rules, should the rules ultimately be upheld, while at the same time offering relief from the rules (to the end of 2031 in the case of the greenhouse gas Final Rule, and to 2034 in the case of the 2024 ELG

Rule) but only if binding commitments to retire are made during the limited window of time while the rules are still under appeal and regulatory uncertainty prevails. For this reason, and given the combined effect of the two rules, issued at the same time by EPA and as part of a package of four power plant rules, it is imperative that both the 2024 ELG Rule and the greenhouse gas Final Rule be stayed.

46. *Increased Labor, Procurement, Financing, and Fuel Supply Costs*. As a result of the Final Rule, Buckeye will be required in 2026 (and as early as 2025 under the 2024 ELG Rule) to make a binding commitment to retire its Cardinal Units by no later than the end of 2031 (and by the end of 2034 under the 2024 ELG Rule). And all coal-fired units in the country will be required to make compliance decisions resulting from the Final Rule (and the companion 2024 ELG Rule), many of which are also likely to make the determination that retirement by the end of 2031 (and/or by the end of 2034 under the 2024 ELG Rule) is the only viable compliance option. When this binding commitment is made, and even before the Final Rule (and the associated 2024 ELG Rule) is likely to have made its way through the appeals

process, this commitment (and the issuance of the Final Rule and the 2024 ELG Rule) is likely to have negative and immediate effects on labor, procurement, financing, and fuel supply costs.

47. Shutting down Cardinal Units 1 and 2 will require Buckeye to eliminate more than 200 full-time jobs. In addition to causing significant disruptions to the community and to Buckeye's employees and their families, the mandatory nature of these reductions may also increase the cost of labor in the near term. Labor costs may be higher for positions that are due to be eliminated.

48. Furthermore, the Final Rule may cause certain equipment suppliers to exit the coal-fired power industry or to increase their costs, knowing that most or all coal-fired power generation, i.e. their customers, will, as a result of the Final Rule, be required to retire or to reduce their operations anywhere from 2030 to 2038, and by the end of 2031 at Cardinal and likely many other coal-fired units, such as OVEC's.

49. The same dynamic is likely to affect coal suppliers. Buckeye has already seen some coal suppliers fail to offer coal supply beyond 2027

because of concerns about the future of coal-fired generation and, accordingly, their ability to stay in business.

50. Rating agencies may lower Buckeye's credit ratings as a result of the Final Rule and the 2026 binding commitment to retire by the end of 2031, and lenders may increase their borrowing costs to Buckeye, coal suppliers, and other vendors and service providers dependent on coal-fired EGUs as customers.

II. Impacts at Clifty Creek and Kyger Creek

51. As mentioned above, Buckeye is a minority (18%) co-owner of two generation facilities that are operated by OVEC. The Clifty Creek facility has six affected coal-fired EGUs, and the Kyger Creek facility has five affected coal-fired EGUs. As a result of its minority ownership and contractual rights to power, Buckeye receives approximately 400 MW of electricity from these two facilities.

52. Decisions about compliance at these facilities are not solely Buckeye's to make, and instead must be made by OVEC's Board of Directors and its management. Decision-making about the compliance plans for Clifty

Creek and Kyger is still in process. Even so, and for many of the same reasons discussed herein with regard to the Cardinal Units, it is likely that OVEC will also make the decision to retire its units by the end of 2031 (and/or by the end of 2034) as a result of the Final Rule (and its companion 2024 ELG Rule), and regardless, each of the available compliance pathways under the Final Rule would require Buckeye to immediately begin incurring substantial expenses from OVEC as it responds to the Final Rule (and 2024 ELG Rule) and evaluates compliance alternatives and potential retirement commitments that must be made as soon as 2026 (and 2025 under the 2024 ELG Rule).

53. If these facilities find it possible to comply with and decide to comply with either the long-term or medium-term subcategory, OVEC would need to begin making immediate plans and expenditures to assure that either CCS would be in service before 2032 or natural gas co-firing would be available before 2030. That would create immediate expenses for Buckeye. Yet if these facilities select the retirement applicability exemption, then Buckeye would need to begin making immediate expenditures related

to securing 400 MW of replacement power, whether that be from the market or from new owned or controlled generation, as discussed above related to Cardinal. If purchased from the market, those replacement power costs would reach roughly **$50-200 million** (using the same assumptions as above about the costs of replacement power in the market during the period 2032 to 2040 as compared to the expected costs to operate OVEC's EGUs during that same period).

ABSENT A STAY, BUCKEYE WILL SUFFER IMMEDIATE IRREPARABLE HARM

54. *Immediate replacement power costs*. The Final Rule will require Buckeye to secure replacement power as a result of the forced retirements of the Cardinal Units. There are only two options for replacement power. The first option is to build new generation. If Buckeye decides that it must replace the retired generation with other owned or controlled generation, then Buckeye will incur immediate costs to begin the design, planning, site selection and acquisition, equipment procurement, construction, contracting, permitting, financing, fuel supply, and other processes associated with building or acquiring new generation, even gas peakers.

55. Given that many existing generators are likely to also be forced into retirement before 2032 in order to claim an applicability exemption, much new replacement generation will be required across the country, resulting in cost increases and delays for all new generation projects. Planning and execution will need to begin immediately for such replacement generation to be in service before 2032. The second option is to purchase power from the market. But power markets are highly volatile, which exposes Buckeye and its members to large price swings and counterparty risk. If other power generators turn to the market all at once, that volatility will only become more pronounced. Planning for and attempting to mitigate the effects of this volatility has its own costs, such as developing and implementing a hedging strategy and plan. Buckeye cannot solve this volatility by simply building or buying new generation resources. Low-load "peaking" units are the only viable option for replacement capacity under the Final Rule. But the Final Rule also caps the capacity factor of these units, limiting them to 20%. That means they must be left idle 80% of the time. Purchases of market power would still be required during that time.

Therefore, Buckeye would still be exposed to market volatility and associated hedging costs even if it were to pursue a strategy of building or buying new generation resources to meet the replacement power needs that the Final Rule creates. Accordingly, no matter what compliance path Buckeye chooses, the costs of replacement power will begin accruing immediately.

56. *Immediate planning costs*. As mentioned above, as a result of the Final Rule (and companion 2024 ELG Rule), Buckeye will immediately begin incurring costs to model its portfolio without the Cardinal Units (and likely without the OVEC Units as well) after 2031, and to evaluate how best to replace that power supply whether that be from the market or replacement generation, or some combination of both. If replacement generation, as opposed to market power is the chosen alternative, the type of replacement power would also need to be determined, although in order to meet a 2031 in-service date, gas peakers seem to be the only viable option. This planning will also require Buckeye to spend money on portfolio and supply planning,

including associated hedging strategies, and to divert significant internal resources to analyzing the Final Rule's effects.

57. *Immediate Stranded Costs*. The Final Rule requires Buckeye to make a legally binding commitment for any retirements by 2026 (and by 2025 under the 2024 ELG Rule), when state implementation plans are due. As a result of such binding commitment, and as mentioned above, under accounting rules, Cardinal Units 1 and 2 will immediately become abandoned units, and Buckeye will no longer be able to list such assets as plant in service or depreciate these assets on its books. Buckeye will be required to immediately, in 2026 (or 2025 if the NOPP is made under the 2024 ELG Rule), expense any remaining book value for these units or to create and amortize a regulatory asset that will also result in increased rates if amortized over the period through 2031. The same dynamic will occur with any new or replacement capital assets at Cardinal placed in service starting in 2026 after the Cardinal Units become abandoned but prior to their actual retirement at the end of 2031 (or earlier). As mentioned above, the Final Rule could even result in a decision to retire the Cardinal Units prior

to 2031, and even while the Final Rule is still under appeal, if a major capital investment is required to be made (*e.g.*, an expensive repair or replacement), whether as a result of equipment failure or even other EPA rules, that could not be economically justified given the shorter remaining life of the plant resulting from the Final Rule.

58. If the 2024 ELG Rule is not stayed (or if the greenhouse gas Final Rule is not stayed and fully adjudicated and overturned by the end of 2025), and if Buckeye decides to make the additional investments required by the 2024 ELG Rule, rather than to commit in 2025 to retire the Cardinal Units by 2034 and avoid 2024 ELG compliance costs as permitted under the 2024 ELG Rule, these investments will become stranded investments should the Final Rule ultimately be upheld, as these investments will need to begin to made immediately in order to meet the 2029 compliance date required under the 2024 ELG Rule. If the Final Rule is upheld and the 2024 ELG Rule compliance investments are not completed at that time, Buckeye would likely cease any further investments in 2024 ELG Rule compliance and choose to retire in 2029, rather than continue to make further investments in 2024 ELG Rule

compliance, which only allow for operations for two years after 2029 until the 2031 retirement date for Cardinal resulting from the Final Rule. All of Buckeye's investments in 2024 ELG Rule compliance would then become stranded assets. In such a case, Buckeye's investments in 2020 ELG Rule compliance will also become stranded investments, as they will only be in service for the four-year period between the 2025 date for 2020 ELG Rule compliance and the 2029 date for 2024 ELG Rule compliance. If, instead, Buckeye would choose to complete 2024 ELG Rule compliance investments, these and the investments already made in 2020 ELG Rule compliance would still become stranded investments, as they will only be in service for six years, in the case of 2020 ELG Rule compliance investments (for the period between 2025 and 2031), and for two years, in the case of 2024 ELG Rule compliance (for the period between 2029 and 2031).

59. On the other hand, if Buckeye chooses by the end of 2025 to issue the NOPP under the 2024 ELG Rule and commit to retire Cardinal by 2034 (as a result of uncertainty about the greenhouse gas Final Rule's ultimate fate before the courts), then even if the Final Rule is ultimately overturned, such

relief will be illusory (if the 2024 ELG Rule is not also overturned), as Buckeye will have made a commitment in 2025 to retire Cardinal by 2034, even if Buckeye would have otherwise been willing to make the investments in 2024 ELG Rule compliance allowing Buckeye to operate indefinitely past 2029 had Buckeye known, at the time it was otherwise required to make the 2024 ELG Rule NOPP election in 2025, that the power plant greenhouse gas Final Rule would ultimately be ruled invalid.

60. *Immediate Labor, Procurement, Financing and Fuel Supply Costs.* As mentioned above, the Final Rule is likely to result in immediate increases in labor, procurement, financing and fuel supply costs, and could result in some suppliers leaving the industry entirely, as under the Final Rule, all coal-fired power plants will be required to retire by no later than 2038 and most by 2031, given that CCS and all compliance options other than retirement are technically and commercially not achievable before 2030, if at all. This same dynamic is caused by the binding retirement decisions that must be made no later than the middle of 2026 (if not sooner, given that States will call for State-plan information long before the plans are due), both

for the Cardinal Units, OVEC, and other coal-fired power plants across the country, as well as the retirement decisions that must be made by 2025 under the 2024 ELG Rule.

61. *Immediate costs to Buckeye's members and consumers.* All of these near-term costs will begin flowing to Buckeye's members—and ultimately to the rural consumers who depend on Buckeye to keep their lights on when it is dark and to keep their heaters on when it is cold.

62. These costs are not reversible. Equipment generally cannot be returned without cost. Dollars spent on portfolio modeling, generating facility design, planning, permitting, engineering, site selection and acquisition, fuel procurement, financing and other studies and costs cannot be refunded. Legally binding retirement promises generally cannot be undone. Buckeye might even be forced into a retirement decision earlier than 2031, perhaps while the Final Rule is still on appeal, if a major capital expenditure at the Cardinal is required to be made as a result of equipment failure, or other EPA rules, such as the 2024 ELG Rule, that could not be

justified given the before-2032 retirement date that is Buckeye's only viable option under the Rule.

63. Moreover, these costs cannot be deferred or delayed until the courts reach a final determination on the merits of this litigation. Optimistically, Buckeye expects that process to take *at least* 2-3 years. But the Rule's compliance deadlines do not give Buckeye any time to spare. On the contrary, time is of the essence, unless the Final Rule is stayed.

64. In sum, if the Final Rule remains in effect while this litigation is pending, Buckeye will have no choice but to incur significant unrecoverable compliance costs as well as to shoulder the many other substantial, immediate, and irreparable harms described above.

* * *

I declare under penalty of perjury under the laws of the United States of America, pursuant to 28 U.S.C. § 1746, that the foregoing is true and correct to the best of my knowledge.

Executed on this 9th day of May, 2024, in Columbus, OH.

Craig Grooms

EXHIBIT 20

DECLARATION OF J. MICHAEL BROWN

1. I am the Environmental Safety and Health Director for Ohio Valley Electric Corporation (OVEC), including its wholly owned subsidiary, Indiana-Kentucky Electric Corporation (IKEC)[1]. I am responsible for directing corporate environmental permitting and compliance activities, corporate safety policies and procedures, and certain energy scheduling functions, including the offering of OVEC's generating units into the PJM Market. I also serve as the company's Designated Representative (DR) for managing the air emission allowance accounts for each of OVEC's generating stations via USEPA's Clean Air Market Division (CAMD). Given my responsibilities and role at OVEC, I also serve as a duly authorized representative for certifying NPDES permits and compliance documents issued to OVEC from the State of Indiana and Ohio pursuant to their respective delegated authorities in compliance the Clean Water Act (CWA). I provide this declaration in support of the motion to stay the final rule of the U.S. Environmental Protection Agency, titled "**SUPPLEMENTAL EFFLUENT LIMITATIONS GUIDELINES AND STANDARDS FOR THE STEAM ELECTRIC POWER GENERATING POINT SOURCE CATEGORY**" (Supplemental ELG Rule) , filed by Petitioners in Case No. 24-2123, while legal proceedings associated with this rulemaking are ongoing.
2. This declaration is based on my personal knowledge of facts, my consultation with other utilities and OVEC's Sponsoring Company personnel, and analysis conducted by my staff.
3. I have been responsible for overseeing OVEC environmental compliance activities since 2011. During my time at OVEC, I have been responsible for directing the overall corporate environmental safety and health compliance, including environmental compliance, at OVEC's two coal-fired generating stations located in Madison, Indiana and Cheshire, Ohio.
4. My utility career spans over 33 years, all in the field of environmental compliance.
5. I graduated with a Bachelor of Science degree from Penn State University and earned a Master of Business Administration from Capital University.
6. OVEC and IKEC were organized in October 1952 by 15 sponsoring utilities (referred to as "Sponsoring Companies") to provide the electric power requirements of the Atomic Energy Commission's (as predecessor to the Department of Energy (DOE)) gaseous

[1] As used herein, the term "OVEC" refers to the combined OVEC and IKEC business.

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diffusion uranium enrichment plant in Piketon, Ohio. Since that supply agreement was terminated by the DOE in 2003, the entire generating capacity has been committed to the Sponsoring Companies under the terms of an inter-company power agreement (ICPA) in effect through June 30, 2040.

7. OVEC employs a total of approximately 520 direct workers and more than 100 full-time local contractors at its two generating stations and the corporate headquarters located in Piketon, Ohio. OVEC also maintains 705 circuit miles of high voltage 345 kV transmission lines that form part of the bulk electric transmission system that is the backbone of the region's power supply, helping to ensure safe and reliable base-load generation to the eastern half of the United States.
8. With a majority of the Sponsoring Companies located in Ohio and over 90% of all Sponsoring Companies in PJM, OVEC continues to provide strong support to the bulk electric system in the Midwest.
9. The premature retirement of OVEC's two coal-fired generating stations would result in the loss of approximately 500 direct jobs, with a payroll in excess of 50 million dollars, as well as the loss of myriad ancillary jobs in our local communities and from our suppliers (including coal suppliers).
10. OVEC also pays in excess of 6 million in total annual real estate and property taxes in the communities where our facilities are located.
11. I am submitting this declaration because absent a stay, the Environmental Protection Agency's (EPA) Supplemental ELG Rule creates immediate harm in the form of near-term decisions with respect to future plant operations and the timing of "cessation of operation" that OVEC's Boards of Directors and the OVEC Senior Management Team will be forced to make (and may not be possible to change) long before the outcome of litigation is known. In the interim, the Supplemental ELG Rule could result in the premature retirement of OVEC's generation stations prior to the end of the existing term of the ICPA on June 30, 2040, and ultimately the premature dissolution of OVEC itself.
12. One example of a near-term decision involves actions required of utilities to support state-level decision-making to implement the Supplemental ELG Rule. Specifically, each existing coal-fired electric generating unit subject to this rulemaking must either choose to invest in unproven and costly ZLD technologies, and work with their respective state permitting authorities on a schedule for compliance that is "as soon as possible," but no later than December 31, 2029, while concurrently spending millions of dollars on technology to separately comply with the 2020 ELG Rule requirements that are still

required, but will become obsolete by 2029. The only other option would be to file a Notice of Planned Participation (NOPP) and commit to permanently cease coal combustion at each generating station by no later than December 31, 2034. Further, that decision must be made and an NOPP filed with USEPA by no later than December 31, 2025, and it must include a certification statement validating that the unit(s) are fully compliant with all provisions of the 2020 EGL rule.

13. OVEC submits that ZLD is not the best available technology economically achievable for FGDWW for the myriad reasons addressed in this litigation. ZLD is not adequately demonstrated on a commercial scale for the FGDWW flows at OVEC's facilities and it is a nascent technology at best, and attempted installation is prohibitively costly for most power plants in the nation. There are currently no large-scale domestic applications of membrane filtration systems and only a handful of thermal evaporation and spray dryer applications in service. Despite this lack of proven and available technology at the utility scale, EPA still claims these as BAT technologies in the 2024 rule. It is also simply not physically possible to engineer, design, construct, and install ZLD by December 31, 2029, at OVEC's power plants - the myriad reasons more eloquently documented in the numerous Declarations outlined in the emergency stay requests filed on this rule by other utilities that find themselves under similar or the same circumstances.
14. Separately, even if the EPA were correct (which they are not) with respect to the availability of ZLD for FGD wastewater and other waste streams, it is not economically achievable. As reported in The Electric Power Research Institute's (EPRI) Comments on the Proposed Revised Effluent Limitations Guidelines Rule (date or footnote), for FGDWW treatment systems, EPRI's capital cost estimate is 9x higher than EPA's capital cost estimate, EPRI's O&M cost estimate is more than 40x higher than EPA's O&M cost estimate, and in evaluating the total annualized costs, EPRI's estimate of industry cost is more than 25x higher than EPA's estimate. For Kyger Creek Station and Clifty Creek Station, the EPRI estimated capital cost to convert from CP and biological treatment, to membrane filtration and brine encapsulation is $159 million and $221 million respectively, compared to the EPA estimate of $18 million and $27 million.
15. If OVEC chooses any compliance path other than to "install ZLD" for the bottom ash transport water (BATW), FGDWW, and CRL at its generating stations, it may trigger an alleged default under OVEC's long-term debt and/or result in unnecessary and premature termination of the ICPA, as no other compliance option is available that would

permit OVEC to continue running its generating units consistent with its ICPA contractual terms and conditions through June 30, 2040.

16. OVEC is a privately held company that provides electricity via a contractual relationship with its Sponsoring Companies. Any external regulatory action that results in OVEC being required to plan for a plant closure that is earlier than the end of the term of the ICPA could result in the immediate declaration of an alleged default of OVEC's long-term debt, and result in premature wind-down and dissolution of OVEC. As further explained in this declaration, EPA's Supplemental ELG Rule (as well as other rules EPA released in 2024 targeting steam electric generating facilities) will harm OVEC and could ultimately result in the premature cessation of facility operations a full decade prior to the end of the June 30, 2040 term of the ICPA.

OVEC OPERATIONS

17. OVEC employs approximately 520 full-time employees in Southern Ohio and Southeast Indiana. OVEC, directly and through its wholly owned subsidiary, IKEC, owns and operates the 5-unit 1,086 MW Kyger Creek Station, in Cheshire, Ohio as well as the 6-unit 1,303 MW Clifty Creek Station in Madison, Indiana. Power from these stations is ultimately provided to our utility Sponsoring Companies under the terms of the ICPA, a long-term power contract that allows them to meet the electricity needs of their residential, commercial, industrial, and wholesale customers. Nearly 25% of OVEC's generation is provided for the benefit of rural electric cooperatives whose service territories are primarily comprised of low-income rural residential customers that depend on reliable and affordable electricity such as the baseload generation OVEC provides.
18. The Clifty Creek Station's six units all have electrostatic precipitators for particulate matter (PM) control, all units have over-fire air for nitrogen oxides ("NOx") control, and five of the six units have selective catalytic reduction (SCR) equipment for NOx control. In addition, Units 1, 2, and 3 and, separately, Units 4, 5, and 6, are scrubbed for sulfur dioxide (SO2) control via two Jet bubbling reactor (JBR) scrubbers that came on line in 2013. The scrubber design is robust, and the facility is able to meet its Mercury and Air Toxics Rule (MATS) emission limits as a co-benefit via the management of the scrubber chemistry and overall performance. The cost for the air pollution controls installed at this facility is in excess of $800 million.

19. The Kyger Creek Station's five units all have electrostatic precipitators for PM control and over-fire air and SCRs for NOx control. In addition, Units 1 and 2 and, separately, Units 3, 4, and 5, are scrubbed for SO2 control via two JBR scrubbers that came on line in 2011 and 2012. The scrubber design is robust, and the facility can meet its MATS emission limits as a co-benefit via the management of the scrubber chemistry and overall performance. The cost for the air pollution controls installed at this facility is in excess of $800 million.
20. In addition to the costs referenced above for myriad compliance obligations under various EPA regulations promulgated under the Clean Air Act, OVEC also has made substantial investments in water pollution control systems required under the Clean Water Act. Specifically, in 2023, the bottom ash handling systems at both the Clifty Creek and Kyger Creek Stations were upgraded to include tanks in a closed-loop configuration (with a purge/blowdown of up to 10%). Both stations also installed new low-volume wastewater treatment systems for a combined total capital cost of approximately $160 million. In addition, the Kyger Creek generating station invested an additional $35 million to convert the facility to a dry fly ash handling system that was placed into service in late 2022. OVEC is now upgrading its flue gas desulfurization wastewater treatment plant at each facility by installing bioreactors. OVEC plans to have the additional treatment systems installed and operational by no later than December 31, 2025, at an additional total capital cost of approximately $70 million. All of these wastewater treatment system investments were needed to comply with the EPA's 2020 Steam Electric Effluent Limitation Guidelines (ELG), as well as EPA's 2015 Coal-combustion residuals (CCR) Regulations, and the $70 million investment currently underway and scheduled to be placed into service in mid-2025 to fulfill regulatory obligations under the 2020 ELG Rule will become an obsolete investment by 2029.
21. The end users of most of the electricity in OVEC's Sponsoring Companies' service territory live in rural areas with some of the lowest economic demographics in the US.
22. OVEC's baseload electric generation resources power the PJM region, and that baseload generation sustains the grid with reliable access to energy. A balanced generation mix including adequate baseload generation and capacity is essential to maintain a safe and reliable grid. This is particularly true given recent forecasts in both PJM and MISO that indicate the mid-west is anticipating unprecedented increases in demand for electricity due to data center installations, vehicle electrification efforts, and other forecasted economic development activities – all at a time when the current

administration has issued myriad regulations designed to force reliable base load fossil generation into retirement.

ADDITIONAL CONTROL REQUIREMENTS UNDER EPA'S SUPPLEMENTAL ELG RULE

23. EPA's ELG Rule will require most, if not all, coal-fired power plants – including OVEC's two power plants – to shut down, pure and simple. The current EPA Rule is one of many (including the 2024 updates to the Mercury and Air Toxics Standards (MATS), the 2024 Greenhouse Gas (GHG) Emission Guidelines for Existing Fossil-fuel Fired Steam Electric Generating Units, 2023 revisions to the "Good Neighbor" Rule, and the 2024 Legacy CCR Surface Impoundment Rule) that impose new substantial additional costs, and in the case of the GHG and ELG rules, require immediate major capital investments in unproven and grossly cost-prohibitive technologies for any coal-fired unit that intends to run beyond 2029, as this rule requires zero-liquid-discharge (ZLD) technologies applicable to scrubber wastewater and other waste streams be installed and fully operational "as soon as possible" but no later than December 31, 2029. The exorbitant costs for the Supplemental ELG Rule itself are self-evident; however, the cumulative cost to comply with the full suite of other new environmental regulations promulgated by the USEPA in 2024 will result in the premature retirement of reliable base-load thermal generation assets. The cumulative impact OVEC specifically faces is a cumulative weight represented by the cost to comply with the full suite of new and costly regulations targeting coal-fired steam electric generating facilities across all media (Air, Water, and solid waste). The collective weight of those rules is designed to accomplish one thing – to force coal plants into retirement.
24. Existing coal-fired generating stations in the States of Ohio and Indiana, including OVEC's units, are covered by the ELG and GHG Rules and both states are part of a broad coalition of states and industry groups, to date, that have already separately challenged this rule via requests for reconsideration, emergency stay requests, or both.
25. Starting in 2024, EGUs in Indiana and Ohio will be required to begin making decisions on how to comply with the ELG and GHG Rules and submit those decisions to the state agencies responsible for developing State Plans to implement the GHG Rule, or by filing NOPPs to prematurely retire generating assets that would otherwise remain in service. Among the early decisions utility companies, including OVEC, must make is which subcategory will apply to each of their units. Compliance options and future facility retirement dates will be determined by these decisions. However, the only viable option

for the vast majority of base-load coal-fired generating units, including OVEC's units, will be to retire, and that will further exacerbate the tenuous hold the regional transmission organizations (RTOs) have on grid reliability, likely jeopardizing reliability for millions of people, and resulting in de-facto generation shifting from reliable thermal base-load generation to renewable generation that cannot provide the capacity needs of the RTOs.

26. ZLD is not viable, not proven, and not cost-effective, and would be rife with uncertainty due to anticipated legal challenges associated with any source's attempt to install this unproven technology. Regardless, OVEC cannot elect this subcategory because it is physically impossible to construct and have the suite of technologies operational at either of its power plants by the end of 2029.
27. Combined with the separate capital investments to comply with the new wastewater treatment mandates in the EPA's new ELG rule finalized in 2024, will be factored into OVEC's Board of Directors and management team's decisions, absent a stay. The impacts of other regulations such as the GHG rule are also part of this equation, as co-firing with gas and running the OVEC units until no later than December 31, 2038, would also require investment and installation of the new ELG Rule wastewater treatment system upgrades "as soon as possible" but by no later than December 31, 2029. The collective weight, new capital-intensive and unproven compliance obligations, combined with back-end constraints on how long the units could operate co-firing with gas, likely would result in one viable option absent a stay – premature unit retirements.
28. Because neither CCS nor gas co-firing, are viable options for OVEC, absent a stay, OVEC will be required to make unit and facility retirement decisions by no later than December 31, 2025, under the ELG rule. In other words, the ELG rule could require OVEC to commit within a few months to retire 2,389 MW of thermal baseload generation nearly a decade prematurely, regardless of what kind of generation and/or transmission reliability issues that may cause the local RTO, PJM. Absent a stay, the decision on the merits will come too late.
29. The OVEC units have been specifically dispatched on numerous occasions in the last few years by PJM to aid in relieving grid reliability issues in both the PJM and the MISO RTO footprints and to provide needed generation capacity during storm events. Implementation of the GHG Rule will eliminate the demonstrated value OVEC's generation provides from a grid reliability standpoint.
30. PJM issued an Energy Transition Report[2] on February 24, 2023, documenting PJM's ongoing study of impacts associated with the energy transition activities that are

underway. This report outlined the pace of resource retirements and replacements through 2030 based on final rules at that time and highlights potential reliability risks to meeting growing electricity demand. Specifically, the analysis shows that 40 GW of existing generation are at risk of retirement, and PJM's study projections indicate that the current pace of new entry would be insufficient to keep up with expected retirements and demand growth by 2030. Unfortunately, PJM's dire analysis is even worse. The reason is simple, PJM's analysis and conclusions expressing these concerns also were based on the previous suite of EPA rules, not on the new set of new environmental regulations targeting thermal baseload fossil generation EPA has rolled out in 2024. These new set of rules, including the GHG and ELG Rules, will drive deeper and faster unit retirements, further exacerbating grid reliability issues PJM raised in their 2023 report, and further validated in their May 8, 2024 statement[3].

OVEC submits that PJMs statement further validates unacceptable reliability and resource adequacy issues that support a stay request.

31. More recently, Ben Fowke, the interim President and Chief Executive Officer of American Electric Power, testified before Congress on May 22, 2024, that, "Our society depends upon a reliable power system. As we embark upon this era of economic growth and technological transformation, customers need an energy system that is available to deliver reliable, affordable, and environmentally sustainable power where and when they need it," he said. "Continued development of the electric system must be a central priority of U.S. energy and economic policy, and we need to think bigger and more comprehensively to address the many opportunities and challenges before us."

    During his testimony, he asked for three major reforms:

    1. Congress works with regulators to ensure electric system resource adequacy and prevent premature retirements of dispatchable power plants. This would include considering the impact of recent rules adopted by the EPA to require carbon capture and sequestration.

    2. Congress should also expedite the deployment of new 24/7 dispatchable and clean generation resources to meet growing consumer demand. This would include encouraging the development of small modular nuclear reactors (SMRs) accelerating the construction of critical infrastructure[2].

[2] energy-transition-in-pjm-resource-retirements-replacements-and-risks.ashx (*Attachment 1)*

[3] 20240508-pjm-statement-on-the-newly-issued-epa-greenhouse-gas-and-related-regulations.ashx (Attachment 2)

3. Congress should encourage FERC's recent efforts to support the efficient development of necessary regional and interregional electric transmission facilities to ensure reliability and assist economic growth and development. Notably, this ELG Rule does nothing to further these reliability goals.

32. RTOs and power generators have no time to devise a diligent plan in future years to ensure compliance with the ELG rule while securing grid reliability and public safety. Despite being urged to do so in public comments, EPA provided no meaningful "safety valve" for reliability in the new Rule. Limited one-year extensions conditioned on approval by EPA are not adequate.
33. Compliance with the Supplemental ELG Rule entails considerable costs in unproven technologies for OVEC, its Sponsoring Companies, and ultimately their customers. Sponsoring Companies' costs include the immediate cost of any OVEC debt that may be rendered in default in the event of a premature unit or facility retirement decision, as well as the cost each Sponsor Company will incur to replace the 2,389 MW generation from OVEC including notifications to their RTOs, balancing authorities, state commissions, cooperative associations, and the actual cost for procuring or building the replacement power consistent with their respective obligations to serve their customers. The costs for OVEC may include corporate "cessation of operations," the range of human resource and retention issues resulting from such an action, impacts to local communities including the loss of tax revenues, and other ancillary costs associated with the dissolution of a local business. The costs will impact not only OVEC, and our local communities, but also our owners and their customers. A portion of these near-term expenditures may not be recovered by OVEC's owners if EPA's Supplemental ELG Rule is ultimately overturned as a result of this litigation.
34. The ELG Rule also sets an aggressive compliance timeframe.
35. Without having the Supplemental ELG Rule stayed and fully adjudicated and overturned by the end of 2025 (or the 2024 GHG rule also stayed), OVEC and many other affected EGUs otherwise planning to operate after 2034 will be faced with the prospect of making an uneconomic environmental expenditure (uneconomic due to the shortened life of OVEC resulting from requirements in the Final GHG Rule), to comply with the 2024 ELG Rule, or making a retirement commitment through the issuance of a Notice of Planned Participation (NOPP) by the end of 2025 under the new ELG rule. Further, a separate retirement commitment required under the GHG Final Rule, is also due to EPA (via the

state SIP revision process) in 2026, and OVEC has no assurance that an NOPP retirement commitment would not remain binding under either rule or that compliance with the 2024 ELG rule by 2029 would be possible if the Final ELG and/or GHG Rule were ultimately overturned at the end of the litigation process.

CONCLUSION

36. The ELG Rule (and the suite of additional EPA Rules issued in 2024) will result in the early closure of OVEC facilities and the dissolution of OVEC itself.
37. This irreparably and immediately harms OVEC, its owners, and our owner's end-use retail customers by requiring OVEC's Sponsors (listed below) to prematurely end the intercompany power agreement in effect through June 30, 2040, and begin the process of seeking replacement power for the 2,389 MW of generation that OVEC's Sponsoring Companies in Indiana, Kentucky, Ohio, Michigan, and West Virginia will lose.

OVEC-IKEC Shareholders and Sponsoring Companies

Sponsoring Company Information				
Parent Entity	**Equity Owner**	**Equity Ownership %**	**Power Participant**	**Power Participation %**
AEP	American Electric Power Co, Inc.	39.17%	Appalachian Power Company	15.69%
			Indiana Michigan Power Company	7.85%
	Ohio Power Company	4.30%	Ohio Power Company	19.93%
Buckeye Power, Inc.	Buckeye Power Generating	18.00%	Buckeye Power Generating	18.00%
Duke Energy	Duke Energy Ohio	9.00%	Duke Energy Ohio	9.00%
FirstEnergy	Ohio Edison Company	0.85%	Allegheny Energy Supply	3.01%
	Allegheny Energy, Inc.	3.50%	Monogahela Power Company	0.49%
	The Toledo Edison Company	4.00%		
PPL	Louisville Gas and Electric	5.63%	Louisville Gas and Electric	5.63%
	Kentucky Utilities	2.50%	Kentucky Utilities	2.50%
Wolverine Power Supply	Peninsula Generation Cooperative	6.65%	Peninsula Generation Cooperative	6.65%
The AES Corporation	Dayton Power & Light	4.90%	Dayton Power & Light	4.90%
CenterPoint Energy, Inc.	Southern Indiana Gas & Electric	1.50%	Southern Indiana Gas & Electric	1.50%
Vistra	N/A	N/A	Vistra Vision	4.85%

38. OVEC sees the combined effect of the 2024 ELG rule and the 2024 Greenhouse Gas Final Rule to specifically pressure affected EGUs to make binding commitments to retire, whether by no later than December of 2025 under the 2024 ELG Rule, and/or by 2026 under the greenhouse gas Final Rule, by forcing OVEC to face the prospect of having to make uneconomic or technically impossible investments required under the rules, that are ultimately unlikely to be upheld. Further, absent a stay, if the utilities ultimately prevail in court, it could be too late to unwind the sponsor's efforts to prematurely end the OVEC contract, announce unit closures, and seek replacement power. Both the ELG and GHG rules require binding commitments for the "cessation of coal combustion" that are to be made during the limited window of time while the rules are still under appeal and regulatory uncertainty prevails. For this reason, and given the combined effect of the two rules issued at the same time by EPA and as part of a package of four power plant rules designed to unlawfully force generation shifting, it is imperative that both the 2024 ELG Rule and the greenhouse gas Final Rule be stayed.
39. For the reasons described above, OVEC, its sponsors, and potentially its sponsors' customers are facing substantial and irreparable harm from the implementation of the ELG Rule unless this rule is stayed.

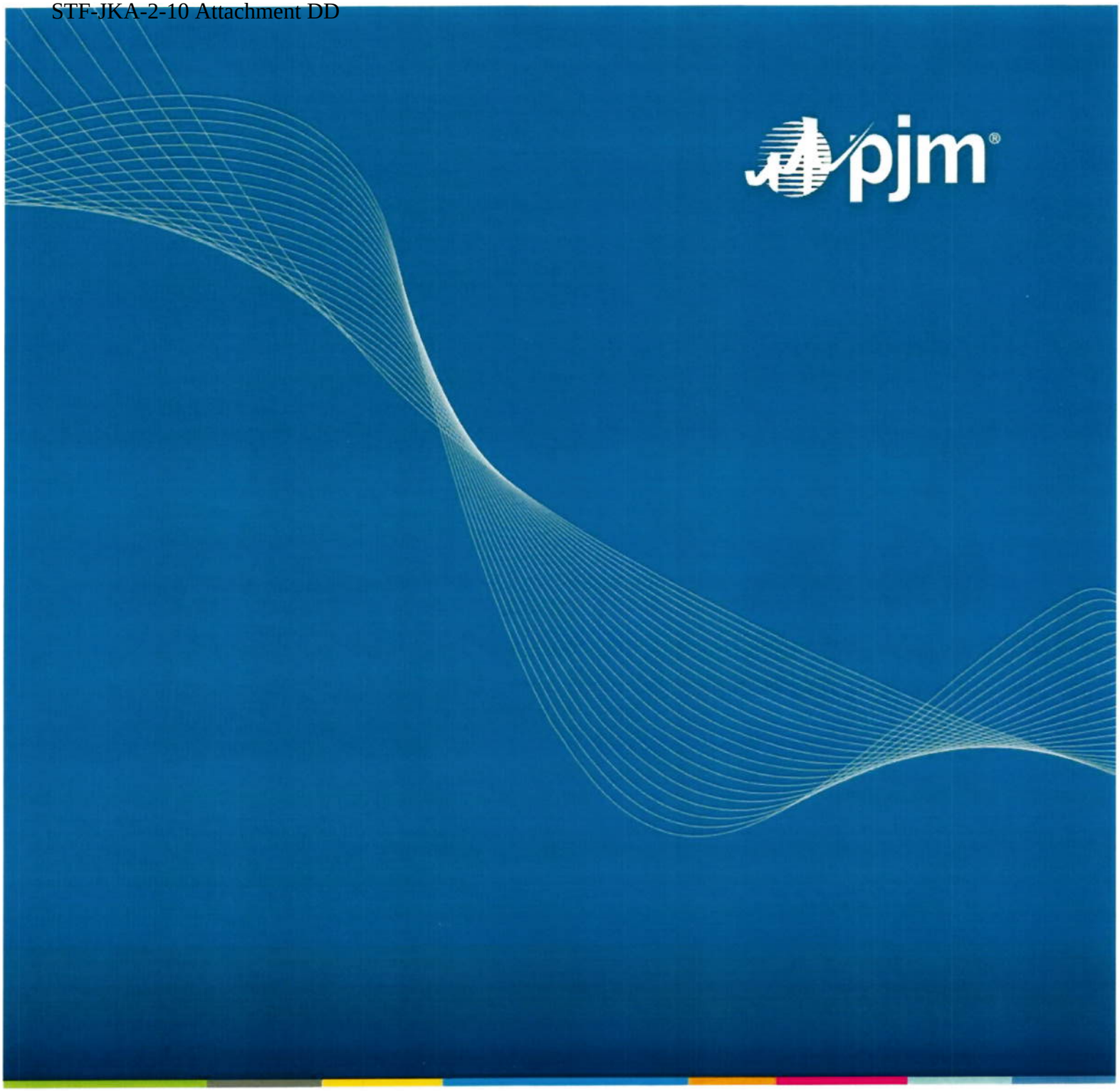
I, J. Michael Brown, declare under penalty of perjury that the foregoing is true and correct. Executed this 20th day of June 2024.



J. Michael Brown

Attachment I

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Energy Transition in PJM:
Resource Retirements, Replacements & Risks

Feb. 24, 2023

For Public Use

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Executive Summary

Driven by industry trends and their associated challenges, PJM developed the following strategic pillars to ensure an efficient and reliable energy transition: facilitating decarbonization policies reliably and cost-effectively; planning/operating the grid of the future; and fostering innovation.

PJM is committed to these strategic pillars, and has undertaken multiple initiatives in coordination with our stakeholders and state and federal governments to further this strategy, including interconnection queue reform, deployment of the State Agreement Approach to facilitate 7,500 MW offshore wind in New Jersey, and coordination with state and federal governments on maintaining system reliability while developing and implementing their specific energy policies.

In light of these trends and in support of these strategic objectives, PJM is continuing a multiphase effort to study the potential impacts of the energy transition. The first two phases of the study focused on energy and ancillary services and resource adequacy in 2035 and beyond. This third phase focuses on resource adequacy in the near term through 2030.[1]

Maintaining an adequate level of generation resources, with the right operational and physical characteristics[2], is essential for PJM's ability to serve electrical demand through the energy transition.

Our research highlights four trends below that we believe, in combination, present increasing reliability risks during the transition, due to a potential timing mismatch between resource retirements, load growth and the pace of new generation entry under a possible "low new entry" scenario:

- The growth rate of electricity demand is likely to continue to increase from electrification coupled with the proliferation of high-demand data centers in the region.
- Thermal generators are retiring at a rapid pace due to government and private sector policies as well as economics.
- Retirements are at risk of outpacing the construction of new resources, due to a combination of industry forces, including siting and supply chain, whose long-term impacts are not fully known.
- PJM's interconnection queue is composed primarily of intermittent and limited-duration resources. Given the operating characteristics of these resources, we need multiple megawatts of these resources to replace 1 MW of thermal generation.

[1] See Energy Transition in PJM: Frameworks for Analysis | Addendum (2021), and Energy Transition in PJM: Emerging Characteristics of a Decarbonizing Grid | Addendum (2022).

[2] See previous work on Reliability Products and Services, including PJM's Evolving Resource Mix and System Reliability (2017), Reliability in PJM: Today and Tomorrow (2021), Energy Transition in PJM: Frameworks for Analysis | Addendum (2021), and work completed through the RASTF and PJM Operating Committee (2022).

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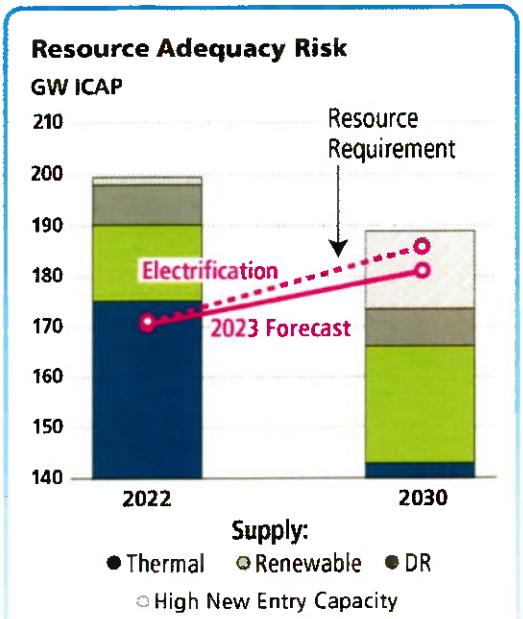
The analysis also considers a "high new entry" scenario, where this timing mismatch is avoided. While this is certainly a potential outcome, given the significant policy support for new renewable resources, our analysis of these long-term trends reinforces the importance of PJM's ongoing stakeholder initiatives, including capacity market modifications, interconnection process reform and clean capacity procurement, and the urgency for continued, combined actions to de-risk the future of resource adequacy while striving to facilitate the energy policies in the PJM footprint.

The first two phases of the energy transition study assumed that PJM had adequate resources to meet load.

In this this third phase of this living study, we explore a range of plausible scenarios up to the year 2030, focusing on the resource mix "balance sheet" as defined by generation retirements, demand growth and entry of new generation.

The analysis shows that 40 GW of existing generation are at risk of retirement by 2030. This figure is composed of: 6 GW of 2022 deactivations, 6 GW of announced retirements, 25 GW of potential policy-driven retirements and 3 GW of potential economic retirements. Combined, this represents 21% of PJM's current installed capacity[3].

In addition to the retirements, PJM's long-term load forecast shows demand growth of 1.4% per year for the PJM footprint over the next 10 years. Due to the expansion of highly concentrated clusters of data centers, combined with overall electrification, certain individual zones exhibit more significant demand growth – as high as 7% annually.[4]



The projections in this study indicate that it is possible that the current pace of new entry would be insufficient to keep up with expected retirements and demand growth by 2030.

On the other side of the balance sheet, PJM's New Services Queue consists primarily of renewables (94%) and gas (6%). Despite the sizable nameplate capacity of renewables in the interconnection queue (290 GW), the historical rate of completion for renewable projects has been approximately 5%. The projections in this study indicate that the current pace of new entry would be insufficient to keep up with expected retirements and demand growth by 2030. The completion rate (from queue to steel in the ground) would have to increase significantly to maintain required reserve margins.

In the study, we also consider generation entry beyond the queue using projections from S&P Global. Those projections indicate that, despite eroding reserve margins, resource adequacy would be maintained if the influx of renewables materializes at a rapid rate and gas remains the transition fuel, adding 9 GW of capacity. The analysis performed at the Clean Attribute Procurement Senior Task Force (CAPSTF) also suggests that further gas expansion is economic and competitive.[5]

[3] Unless otherwise noted, thermal capacity values are expressed in ICAP, without adjustment for EFORd.

[4] PJM Load Forecast Report, January 2023.

[5] CAPSTF Analysis, Initial Results; Emmanuele Bobbio, Sr. Lead Economist – Advanced Analytics, PJM, Dec. 16, 2022.

Balance Sheet Summary (2022–2030)				
Retirements **40 GW** **60% Coal** **30% Natural Gas** **10% Other**	**New Entry Wind/Solar[6]** **Low =** 48 GW-nameplate / 8 GW-capacity **High =** 94 GW-nameplate / 17 GW-capacity	**New Entry Standalone Storage** **Low =** 3 GW **High =** 4 GW	**New Entry Thermal** **Low =** 4 GW **High =** 9 GW	**Load Growth** **2023 Forecast =** 11 GW **Electrification Forecast =** 13 GW
Unless otherwise noted, thermal capacity values are expressed in ICAP, without adjustment for EFORd.				

For the first time in recent history, PJM could face decreasing reserve margins should these trends continue. The amount of generation retirements appears to be more certain than the timely arrival of replacement generation resources and demand response, given that the quantity of retirements is codified in various policy objectives, while the impacts to the pace of new entry of the Inflation Reduction Act, post-pandemic supply chain issues, and other externalities are still not fully understood.

The findings of this study highlight the importance of PJM's ongoing stakeholder initiatives (Resource Adequacy Senior Task Force, Clean Attribute Procurement Senior Task Force, Interconnection Process Subcommittee), continued efforts between PJM and state and federal agencies to manage reliability impacts of policies and regulations, and the urgency for coordinated actions to shape the future of resource adequacy. The potential for an asymmetrical pace in the energy transition, in which resource retirements and load growth exceed the pace of new entry, underscores the need to enhance the accreditation, qualification and performance requirements of capacity resources.

The composition and performance characteristics of the resource mix will ultimately determine PJM's ability to maintain reliability. It is critical that all PJM markets effectively correct imbalances brought on by retirements or load growth by incentivizing investment in new or expanded resources.

[6] Includes hybrid projects with battery storage

Background

Resource adequacy is the ability of the electric system to supply the aggregate energy requirements of electricity to consumers at all times, taking into account scheduled and reasonably expected unscheduled outages of generation and transmission facilities. To achieve the goal of resource adequacy, PJM maintains an Installed Reserve Margin in excess of the forecast peak load that achieves a loss-of-load expectation (LOLE) of one day in 10 years. This LOLE standard is consistent with that prescribed in the ReliabilityFirst Corporation standard for planning resource adequacy.[7]

Long-term reliability and resource adequacy are addressed through the combined operation of PJM's electricity markets, and in particular the capacity market, called the Reliability Pricing Model (RPM). Each PJM member that provides electricity to consumers must acquire enough power supply to meet demand, not only for today and tomorrow, but for the future. Members secure these capacity resources for future energy needs through a series of base and incremental capacity auctions, as well as Fixed Resource Requirement plans.

The capacity market ensures long-term grid reliability by procuring the appropriate amount of power supply resources needed to meet predicted energy demand up to three years in the future. These capacity resources have an obligation to perform during system emergencies, and are subject to penalties if they underperform. By matching generation with future demand, the capacity market creates long-term price signals to attract needed investments to ensure adequate power supplies. This exchange provides consumers with an assurance of reliable power in the future, while capacity resources receive a dependable flow of income to help maintain their existing capability, attract investment in new resources, and encourage companies to develop new technologies and sources of electric power.

Methodology

The size, composition and performance characteristics of the resource mix will determine PJM's ability to maintain reliability. This study explores a range of scenarios in the context of resource adequacy, focusing on the resource mix "balance sheet" as defined by demand growth, generation retirements and new entry of generation. Using the methodology described in this section, PJM evaluates the future of resource adequacy by estimating the amount of capacity required to cover load expectations versus expected capacity for the years 2023 through 2030.

The study's initial supply levels are 192.3 GW of installed capacity from generation resources and 7.8 GW of installed capacity from demand response capacity resources. The generation mix is approximately 178.9 GW of thermal resources and 13.3 GW of renewables and storage.[8]

[7] RFC Standard BAL-502-RF-03: Planning Resource Adequacy Analysis, Assessment and Documentation

[8] This value includes the capacity value of run-of-river hydro, pumped storage hydro, solar, onshore wind, offshore wind and battery energy storage.

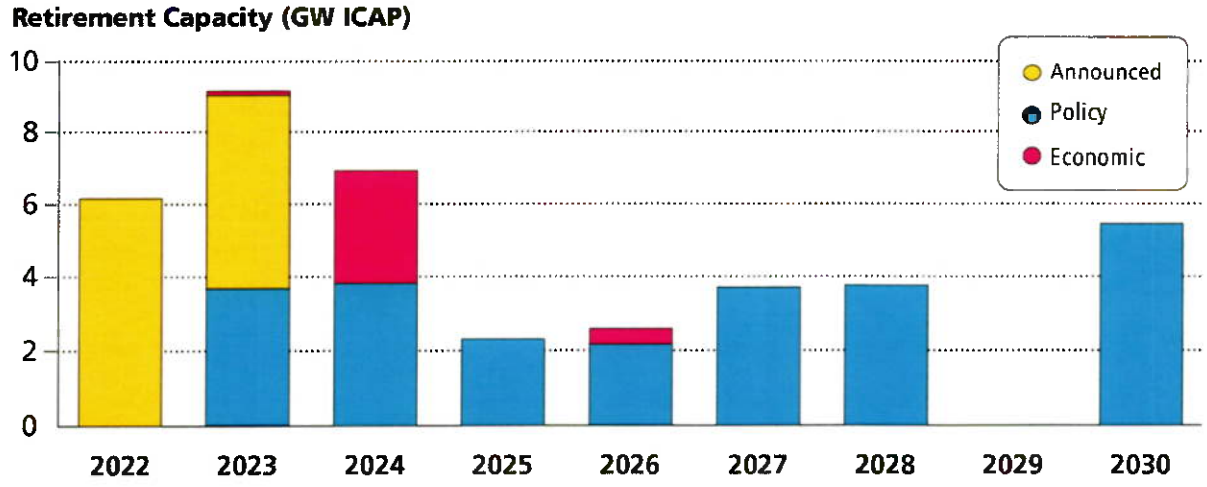
Supply Exits

PJM is undergoing a major transition in the resources needed to maintain bulk power grid reliability.

Historically, thermal resources have provided the majority of the reliability services in PJM. Today, a confluence of conditions, including state and federal policy requirements, industry and corporate goals requiring clean energy, reduced costs and/or subsidies for clean resources, stringent environmental standards, age-related maintenance costs, and diminished energy revenues are hastening the decline in thermal resources.

This study estimates anticipated retirements through 2030 by adding announced retirements with retirements likely as a result of various state and federal policies, and then with those at risk for retirement due to deteriorating unit economics. Potential policy-driven retirements, in this context, reflect resources that are subject to current and proposed federal and state environmental policies, in which it is conservatively assumed that the costs of mitigation and compliance could economically disadvantage these resources to the point of retirement. **Figure 1** highlights the 40 GW of projected generation retirements by 2030, which is composed of: 12 GW of announced retirements[9], 25 GW of potential policy-driven retirements[10] and 3 GW of potential economic retirements. Combined, this represents 21% of PJM's current installed capacity.[11] This section describes each category of potential retirements in more detail.

Figure 1. Total Forecast Retirement by Year (2022–2030)



[9] Includes 6 GW of 2022 retirements.

[10] Note that 7 GW of the 25 GW of supply with policy risk was also identified to have more immediate economic risk. The year that these 7 GW of potential policy retirements shown in **Figure 2** is based on timing identified in the economic analysis. In **Figure 4**, these 7 GW are shown in terms of the regulatory compliance timeline alone. The timeline of these potential quantities of resource retirements does not factor in any reliability "off-ramps" that may be included in established policies.

[11] In this study, PJM assumes that a resource that exits would not return to service in a future delivery year, even if operational conditions improve. Historically, a small percentage of retiring units would instead enter a "mothball" or standby state, in which the unit is put into a state where it may not operate for one or more years; however, in order to obtain an operating permit renewal, the mothballed unit would have to comply with the most recent environmental standards, likely requiring costly upgrades, making investing in newer, cleaner technologies more inviting.

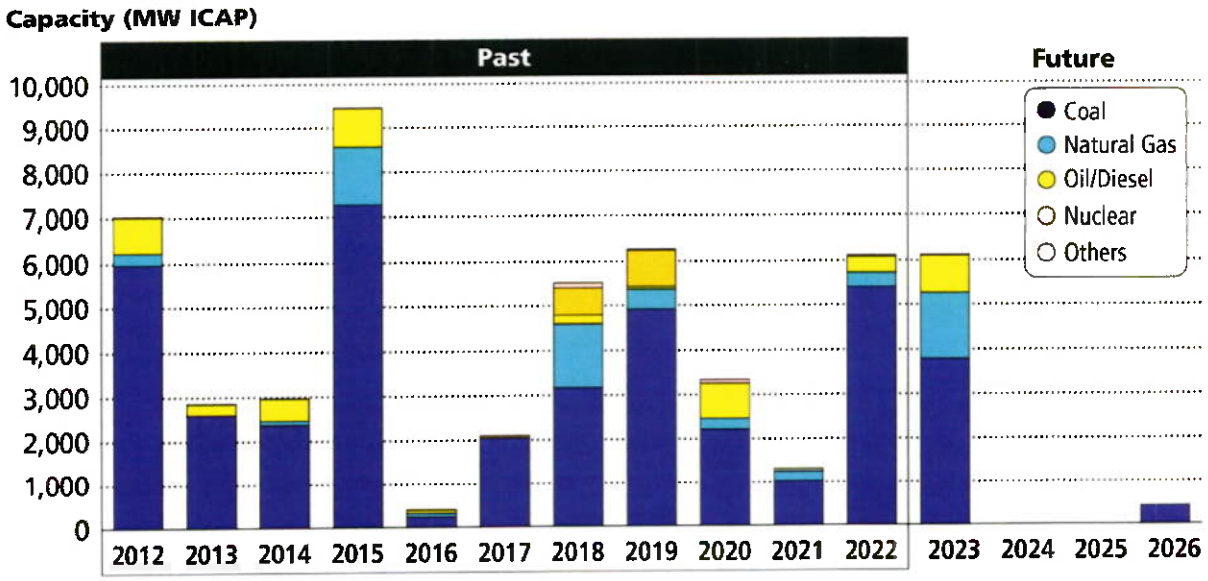
Announced Retirements

One of PJM's responsibilities is to ensure the continued reliability of the high-voltage electric transmission system when a generation owner requests deactivation. Through its Generation Deactivation process,[12] PJM identifies transmission solutions that allow owners to retire generating plants as requested without threatening reliable power supplies to customers. PJM may order transmission upgrades or additions built by transmission owners to accommodate the generation loss. PJM has no authority to order plants to continue operating. However, in some instances, to maintain reliability, PJM may formally request that a plant owner continue operating, subject to rates authorized by the Federal Energy Regulatory Commission (FERC), while transmission upgrades are completed.

Plant owners considering retirement must notify PJM at least two quarters before the proposed deactivation date. PJM and the transmission owners complete a reliability analysis in the subsequent quarter after notification to PJM. Generator retirements and any required system upgrades to keep the grid running smoothly are included in the PJM Regional Transmission Expansion Planning process and are reviewed with PJM members and stakeholders at the PJM Transmission Expansion Advisory Committee.

Between 2012 and 2022, 47.2 GW of generation retired in PJM, as detailed by fuel type in **Figure 2**. In 2022, approximately 6 GW of generation deactivated and an additional 5.8 GW announced ("future") deactivations over the 2023–2026 time frame. The deactivations are slightly above the 10-year average of 4.3 GW, but well under the historical annual peak of 9.5 GW in 2015. Coal-fired resources account for approximately 89% of retired capacity in 2022.

Figure 2. Past and Announced Future Retirements



[12] See process details in PJM Manual 14-D, Section 9, and tracking of deactivation requests at https://www.pjm.com/planning/services-requests/gen-deactivations.

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Potential Policy Retirements

An analysis of federal and state policies and regulations with direct impacts on generation in the PJM region yielded the largest group of potential future retirements in this study.[13] As highlighted in **Figure 3**, the combined requirements of these regulations and their coincident compliance periods have the potential to result in a significant amount of generation retirements within a condensed time frame. These impacts will be reevaluated as these policies and regulations evolve. PJM will continue to work with both federal and state agencies on the development and implementation of environmental regulations and policies in order to address any reliability concerns.

Below are the policies and regulations included in the study:



EPA Coal Combustion Residuals (CCR): The U.S. Environmental Protection Agency (EPA) promulgated national minimum criteria for existing and new coal combustion residuals (CCR) landfills and existing and new CCR surface impoundments. This led to a number of facilities, approximately 2,700 MW in capacity, indicating their intent to comply with the rule by ceasing coal-firing operations, which is reflected in this study.



EPA Effluent Limitation Guidelines (ELG): The EPA updated these guidelines in 2020, which triggered the announcement by Keystone and Conemaugh facilities (about 3,400 MW) to retire their coal units by the end of 2028.[14] Importantly, but not included in this study, the EPA is planning to propose a rule to strengthen and possibly broaden the guidelines applicable to waste (in particular water) discharges from steam electric generating units. The EPA is expecting this to impact coal units by potentially requiring investments when plants renew their discharge permits, and extending the time that plants can operate if they agree to a retirement date.



EPA Good Neighbor Rule (GNR): This proposal requires units in certain states to meet stringent limits on emissions of nitrogen oxides (NOx), which, for certain units, will require investment in selective catalytic reduction to reduce NOx. For purposes of this study, it is assumed that unit owners will not make that investment and will retire approximately 4,400 MW of units instead. Please note that the EPA plans on finalizing the GNR in March, which may necessitate reevaluation of this assumption.



Illinois Climate & Equitable Jobs Act (CEJA): CEJA mandates the scheduled phase-out of coal and natural gas generation by specified target dates: January 2030, 2035, 2040 and 2045. To understand CEJA criteria impacts and establish the timing of affected generation units' expected deactivation, PJM analyzed each generating unit's publically available emissions data, published heat rate, and proximity to Illinois environmental justice communities and Restore, Reinvest, Renew (R3) zones. For this study, PJM focuses on the approximately 5,800 MW expected to retire in 2030.

[13] Policies impacting forward energy prices, such as the Regional Greenhouse Gas Initiative and Renewable Energy Credits, are implicitly included in economic analysis but are not explicitly included in analysis of policy-related retirements.

[14] See State Impact PA, Nov. 22, 2021. These facilities have not filed formal Deactivation Notices with PJM.

New Jersey Department of Environmental Protection CO_2 Rule: New Jersey's CO_2 rule seeks to reduce carbon dioxide (CO_2) emissions of fossil fuel-fired electric generating units (EGUs) through the application of emissions limits for existing and new facilities greater than 25 MW. Units must meet a CO_2 output-based limit by tiered start dates. The dates and CO_2 limits are:

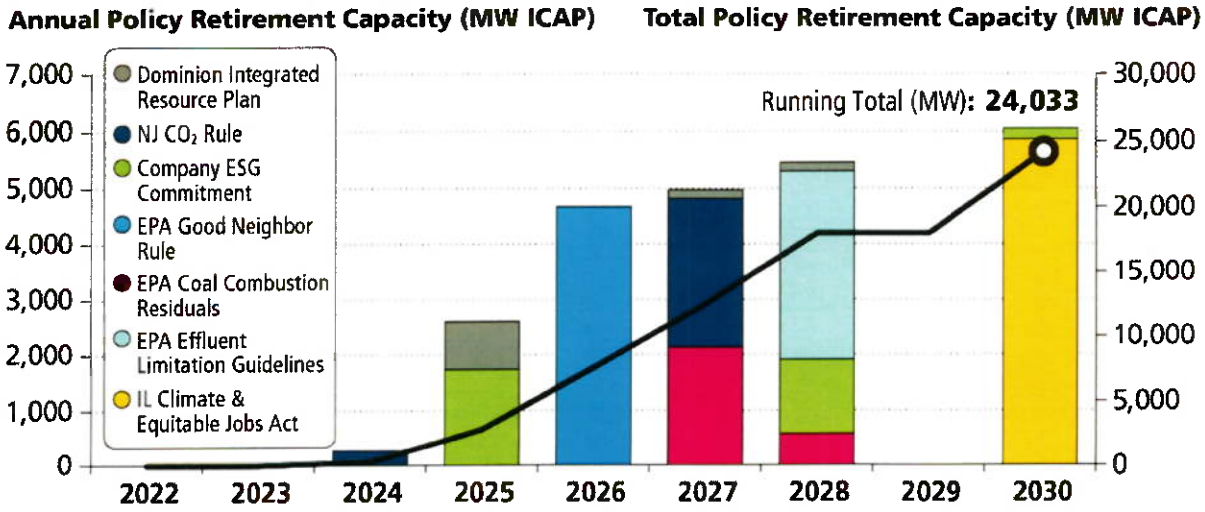
- June 1, 2024 – 1,700 lb/MWh
- June 1, 2027 – 1,300 lb/MWh
- June 1, 2035 – 1,000 lb/MWh

PJM used emissions data found in EPA Clean Air Markets Program Data to evaluate unit compliance. Where a unit's average annual emissions rate was greater than the CO_2 limit on the compliance date, the unit was assumed to be retiring. In this study PJM, estimated retirements at approximately 400 MW in 2024 and approximately 2,700 MW in 2027.

Dominion Integrated Resource Plan (IRP) commits to net zero carbon in its Virginia and North Carolina territory by 2050. PJM studied Dominion's Alternative Plan B retirement schedule, approximately 1,533 MW, for this analysis. Alternative Plan B proposes "significant development of solar, wind and energy storage resource envisioned by the VCEA," (Virginia Clean Economy Act of 2020), while maintaining natural gas generation for reliability, which is reflected in our analysis.

Company ESG (Environmental, Social, Governance) commitments are included where there is a commitment to retire resources per legal consent decree or other public statement. This includes the elimination of coal use and the retirement of the Brandon Shores, 1,273 MW, and Wagner, 305 MW, facilities in Maryland and the retirement of Rockport, 1,318 MW, in Indiana.

Figure 3. Potential Policy Retirements



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Potential Economic Retirements

The third category of retirements in this study, beyond those formally announced and made likely by policy implementation, were identified through an analysis of revenue adequacy, the ability to economically cover going-forward costs from the wholesale markets. A net profit value was calculated for each existing generation resource using an estimate of future revenues and historical costs.

$$Net\ Profit = (\ Gross\ Energy\ \&\ Ancillary\ Service\ Revenue - Production\ Costs\ ) + (\ Capacity\ Revenue\ ) - (\ Fixed\ Avoidable\ Costs\ )$$

The results reveal that a portion of the thermal fleet is at risk of becoming unprofitable in the coming years.

The capacity market's Variable Resource Requirement (VRR) represents the set of prices for which load is willing to procure additional supply beyond the minimum reliability requirement. There are three points in the sloped demand curve, the first of which is anchored at a price 1.5 times the Net Cost of New Entry (Net CONE). Should the auction clear at this price level, the auction result signals that demand is willing to pay for the construction of new supply, minus the expected energy revenues the resource should expect to earn in the energy markets. As such, it is important to align the revenue expectations for the marginal resources with forward revenues, especially under PJM's continually changing landscape of business rules.

Energy & Ancillary Services Revenue and Production Cost

This study used a scaling approach to estimate forward unit-specific energy and ancillary services (E&AS) revenues from historical energy and ancillary service revenues by applying the following:

$$Fwd\ Unit\ E\&AS\ Revenue = Hist\ Unit\ E\&AS\ Revenue * \frac{Fwd\ Reference\ E\&AS\ Revenue^{15}}{Hist\ Reference\ E\&AS\ Revenue} * \frac{Reference\ Avg\ Heat\ Rate}{Unit\ Avg\ Heat\ Rate}$$

For a given reference resource type, unit dispatch was simulated using both historical and forward energy hub-adjusted energy prices. For the equivalent production cost model, the relative ratio of revenues and heat rates indicate the net effects of both rising fuel costs and energy price revenue. A unit on the margin in the energy markets, typically a natural gas unit, would set a locational price near its short-run marginal costs. Infra-marginal units, potentially coal units, would receive higher revenues as price-taking resources, and thus may see increased profitability. This is reflected in the analysis, in which a reference coal unit's forward revenues increased an average of 139% over previous revenue estimates.

[15] The forward energy and ancillary services revenue calculation used in this study is the method that was developed for use in the Forward Net Energy & Ancillary Services Offset calculation originally developed in 2020, and filed as part of the most recent Quadrennial Review.

Capacity Revenues and Fixed Avoidable Costs

Unit-specific capacity revenues were calculated from prices and cleared quantities in the 2023/2024 Base Residual Auction (BRA). The study used the published 2023/2024 BRA Default Gross Avoidable Cost Rate (ACR) values as representative total fixed costs ($/MW-day) required to keep the generating plant available to produce energy. In other words, these are projected costs that could be avoided by the retirement of the plant. Avoidable costs represent operational factors like operations and maintenance labor, fuel storage costs, taxes and fees, carrying charges, and other costs not directly related to the production of energy. When available, unit-specific ACR values from the 2023/2024 BRA supply offer mitigation process were used, otherwise the class average Gross ACR was used.

Results and Estimated Impact

This study assumes that a simulated economic loss would result in a retirement of the resource at the next available delivery year in which the unit is not committed for capacity. As such, a unit with a revenue loss that did not clear in the 2023/2024 BRA would exit in 2023, while a unit with a revenue loss that cleared in the 2023/2024 BRA would exit in 2024. While units that do not clear a single BRA may remain energy-only resources, this conservative assumption was used to provide awareness.

The economic analysis identified approximately 10 GW of supply in immediate economic risk, of which 7 GW of supply is also affected by policy risk, and 3 GW of supply is economic risk only. In aggregate, 6 GW are steam resources, and 4 GW represent combustion turbines and internal combustion resources. Several of the units identified were older steam boilers that had once converted from coal-fired to natural gas fuel; these resources are less efficient than a modern heat-recovery steam generator in a combined cycle unit. Fifty-three percent of the resources identified for economic risk did not have a PJM capacity obligation in Delivery Year 2023/2024, either through the FRR process or market clearing.

Supply Entry

The composition of the PJM Interconnection Queue has evolved significantly in recent years, primarily increasing in the amount of renewables, storage, and hybrid resources and decreasing in the amount of natural gas-fired resources entering the queue. The PJM New Services Queue stands at approximately 290 ICAP GW of generation interconnection requests, of which almost 94% (271 ICAP GW) is composed of renewable and storage-hybrid resources.

Natural Gas Headwinds

In the last decade, resources in the PJM region have benefitted from the proximity to the Marcellus Shale, an area that extends along the Appalachian Mountains from southern West Virginia to central New York. Beginning around 2010, gas extraction from hydraulic fracturing transformed this region into the largest source of recoverable natural gas in the United States. This local fuel supply decreased the prices for spot market natural gas in much of the PJM region, and prices in the PJM region often trade at negative basis to the Henry Hub spot price.

The entry of natural gas resources in the PJM region peaked in 2018, with 11.1 GW of generation commercializing that single year. From 2019 to 2022, a total of 8.1 GW of natural gas generation began service, or about a third of the 23 GW observed from 2015–2018. Queue proposals have also declined; over the last three years, only 4.1 GW of new natural gas projects entered the queue, while 15.1 GW of existing queue projects withdrew.[16]

Recent movement in the natural gas spot markets across the U.S. and Europe add another degree of uncertainty to future operations. In 2022, European natural gas supply faced many challenges resulting from the war in Ukraine and subsequent sanctions against Russia. Liquefied natural gas (LNG) imports into the EU and the U.K. in the first half of 2022 increased 66% over the 2021 annual average,[17] primarily from U.S. exporters with operational flexibility. This international natural gas demand is a new competitor for domestic spot-market consumers, resulting in significantly higher fuel costs for PJM's natural gas fleet.

This study assumes that, of the approximately 17.6 GW of natural gas generation in the queue, only those that are proposed uprates of existing generation, or currently under construction, will complete.[18] This results in 3.8 GW of entry from under-construction natural gas resources to be completed for the 2023/2024 Delivery Year. While 12 GW of natural gas have reached a signed Interconnection Service Agreement (ISA) stage, it is unclear what percentage of this capacity may move forward. If significantly more natural gas capacity achieved commercial operation, it could help avoid reliability issues.

Renewable Transition

PJM's projected resource mix continues to evolve toward lower-carbon intermittent resources. Entry into the queue from renewable and storage resources has been growing at an annualized rate of 72% per year since 2018, or 199 GW of capacity entry versus 2.8 GW commercializing and 42.1 GW withdrawn. This influx of renewable projects has led to a joint effort between PJM and its stakeholders to enact queue reforms intended to clear the backlog of projects, improve procedures around permitting and site control, simplify analysis by clustering projects, and accelerate projects that don't require network upgrades. FERC approved the proposed package in November 2022, with expected implementation in 2023.

Commercial Probability and Expanding Beyond the Queue

PJM staff developed several forecasts of the rate by which projects successfully exit the queue (the "commercial probability" of reaching an *In-Service* state). Since 1997, the PJM New Services Queue has tracked proposed generation interconnection projects from their submittal and study stages to completion of an ISA and Wholesale Market Participation Agreement (WMPA) and construction. At any point in the process, a resource may withdraw from the queue, effectively ending its commercial viability.

[16] This capacity represents natural gas projects that were submitted prior to 2020 and withdrawn in the 2020–2022 time frame.

[17] Europe imported record amounts of liquefied natural gas in 2022, U.S. Energy Information Administration, June 14, 2022.

[18] Under construction includes the New Service Queue *Partially in Service – Under Construction* and *Under Construction* statuses.

The study utilized a logistical regression classification algorithm to predict the probability of a project reaching an *In-Service* entry (or *Withdrawn* exit) based on several properties of the project. A logistical regression searches for patterns within training datasets, resulting in a model that can forecast a probability of a result. After applying the logistical regression model for 10 years of historical project completion (Y-queue to present) without project stage, approximately 15.3 GW-nameplate/8.7 GW-capacity were deemed commercially probable out of 178 GW of projects examined.

The model results for thermal resources were reasonably in line with expectations. However, the model produced extremely low entry from onshore wind, offshore wind, solar, solar-hybrid and storage resources. The uncertainty of completion rates of newer resource types, like offshore wind, likely plays a role in these model outcomes. After adjusting the new renewable capacity by Effective Load Carrying Capability (ELCC) derations, this commercial probability analysis estimates net 13.2 GW-nameplate / 6.7 GW-capacity to the system by 2030, as shown in **Figure 4**.

Given that this process may not capture recent policy changes and fiscal incentives toward renewable and storage development, and that the existing queue has fewer resources entered after 2026, PJM staff utilized two S&P Global Power Market Outlook analyses' generation expansion models. As estimates of future entry beyond the queue, these models are used to provide additional insight for the two scenarios: "Low New Entry" utilizes the "Planning Model,"[19] and "High New Entry" utilizes the "Fast Transition" model.[20] Based on these models, PJM added additional capacity to its commercial probability data in each scenario.

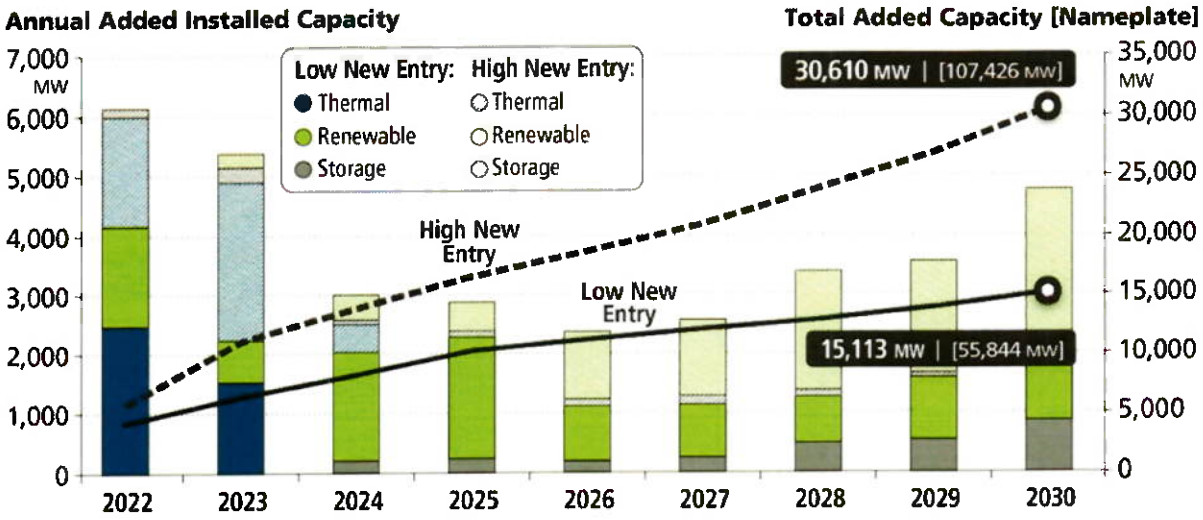
These forecasts of generation expansion are economic resource planning solutions, which take state RPS requirements and capacity margins into account to ensure new renewable builds. Over the study period, the Low New Entry scenario adds 42.6 GW-nameplate/8.4 GW-capacity to supply expectations, resulting in total entry of 55.8 GW-nameplate/15.1 GW-capacity. The High New Entry scenario adds 107 GW-nameplate/30.6 GW-capacity after ELCC derations. Net natural gas entry was approximately 5 GW, and renewables was 48.5 GW-nameplate/10.4 GW-capacity, as shown in **Figure 4**.

[19] S&P Global, North American Power Market Outlook, June 2022, planning model. This planning case incorporated effects from the 2021 Infrastructure Investment and Jobs Act, but not the 2022 Inflation Reduction Act.

[20] S&P Global, North American Power Market Outlook, Sept. 2022, Fast Transition model. This planning case assumes carbon net neutrality by 2050 through the IRA and additional policies, such as state clean energy policies, and as such assumes adjustments for increased electrification of heating, tax credits for renewable generation and higher levels of fossil retirements.

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Figure 4. Forecast Added Capacity



Impact of Capacity Accreditation on Existing Renewables and Storage

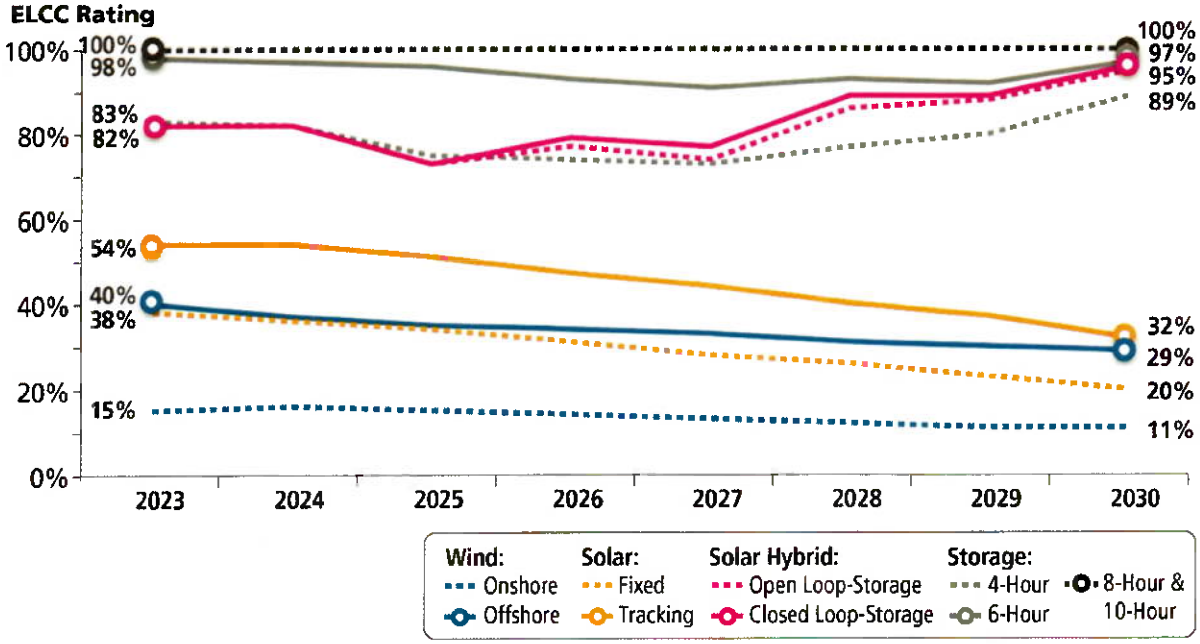
In July 2021, FERC accepted PJM's ELCC methodology for calculating unforced capacity values for intermittent and energy storage capacity resource classes. The ELCC analysis[21] examines load and resource performance uncertainty, and calculates an hourly loss-of-load probability (LOLP) to meet a one-in-10 year loss of load expectation (LOLE) adequacy criteria. The ELCC method examines the alignment of a given resource type's capacity to high risk hours, as well as the change in risk hours proportional to the changes in portfolio size. The adjustments to accredited capacity went into effect in the 2023/2024 BRA executed in June 2022.

This study examined the current renewable generation fleet for the impact of future changes in capacity accreditation. Today, there are approximately 3.5 GW of onshore wind and solar capacity resources participating in the RPM capacity market as intermittent resources. From 2022 to 2030, this accredited capacity is expected to decline by 1.2 GW to 2.3 GW due to portfolio effects resulting in the increase of entry from other intermittent renewable resources.[22] This adjustment is consistent with the renewable expectations presented in the December 2021 Effective Load Carrying Capability (ELCC) Report.

[21] Manual 20, Section 5: PJM Effective Load Carrying Capability Analysis

[22] Approximate nameplate needed to replace 1 MW of thermal generation: Solar – 5.2 MW; Onshore Wind – 14.0 MW; Offshore Wind – 3.9 MW. These are average values.

Figure 5. Effective Load Carrying Capability (ELCC) Rating by Resource Type



Demand Expectations

Load forecasting is an important part of maintaining the reliability of the bulk electric system. Forecasting helps PJM make decisions about how to plan and operate the bulk electric system in a reliable manner, and how to effectively administer competitive power markets. PJM's Resource Adequacy Planning Department publishes an annual Load Forecast Report, which outlines "long-term load forecasts of peak-loads, net energy, load management, distributed solar generation, plug-in electric vehicles and battery storage."

Along with the energy transition, PJM is witnessing a large growth in data center activity. Importantly, the PJM footprint is home to Data Center Alley in Loudoun County, Virginia, the largest concentration of data centers in the world.[23] PJM uses the Load Analysis Subcommittee (LAS) to perform technical analysis to coordinate information related to the forecast of electrical peak demand. In 2022, the LAS began a review of data center load growth and identified growth rates over 300% in some instances.[24] The 2023 PJM Load Forecast Report incorporates adjustments to specific zones for data center load growth, as shown in **Figure 5**.

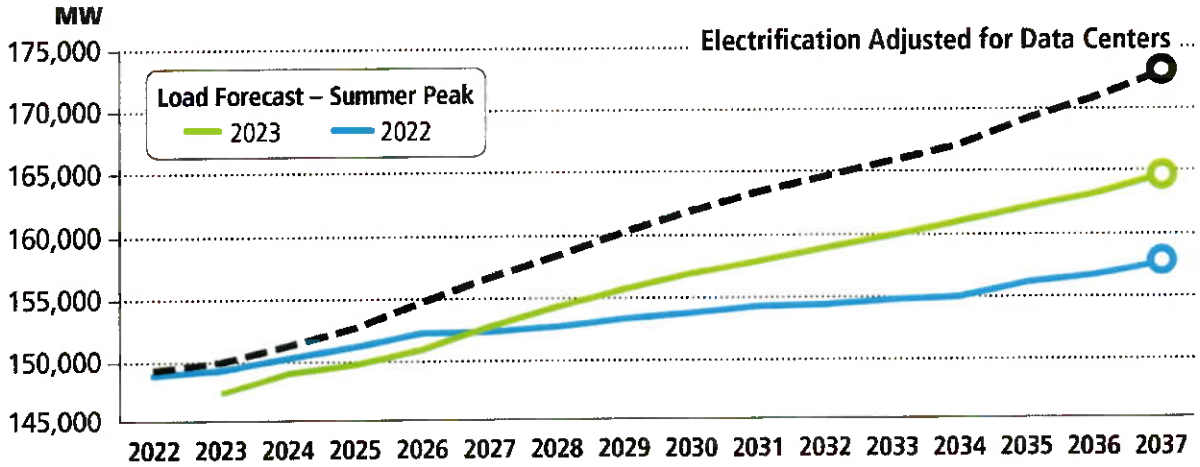
[23] See Loudoun County Department of Economic Development, 2023.

[24] Load Analysis Subcommittee: Load Forecast Adjustment Requests, Andrew Gledhill, Resource Adequacy Planning, Oct. 27, 2022

Additionally, PJM is expecting an increase in electrification resulting from state and federal policies and regulations. The study therefore incorporates an electrification scenario in the load forecast to provide insight on capacity need should accelerated electrification drive demand increases.[25] This accelerated demand increase is consistent with the methodology used in the Emerging Characteristics of a Decarbonizing Grid paper.[26] That paper found electrification to have an asymmetrical impact on demand growth, with demand growth in the winter, mainly due to heating, more than doubling that in the summer. This would move the bulk of the resource adequacy risk from the summer to the winter.

Figure 6 highlights how updated electrification assumptions and accounting for new data center loads have impacted the summer peak between the 2022 and 2023 forecasts.[27]

Figure 6. Impacts of Electrification and Data Center Load on Forecasts



What Does This Mean for Resource Adequacy in PJM?

PJM projects resource adequacy needs through the Reserve Requirement Study (RRS). The purpose of the RRS is to determine the required capacity or Forecast Pool Requirement for future years or delivery years based on load and supply uncertainty. The RRS also satisfies the North America Electric Reliability Corporation/ReliabilityFirst Adequacy Standard BAL-502-RFC-03, Planning Resource Adequacy Analysis, Assessment and Documentation, which requires that the Planning Coordinator performs and documents a resource adequacy analysis that applies a LOLE of one occurrence in 10 years. The RRS establishes the Installed Reserve Margin values for future delivery years. For this study PJM used the most recent 2022 RRS, as well as the 2021 RRS for comparison.

[25] Electrification assumptions are 17 million EVs, 11 million heat pumps, 20 million water heaters, 19 million cooktops in PJM by 2037, built on top of the 2022 Load Forecast.

[26] Energy Transition in PJM: Emerging Characteristics of a Decarbonizing Grid, May 17, 2022.

[27] 2023 Load Forecast Supplement, PJM Resource Adequacy Planning Department, January 2023.

Combining the resource exit, entry and increases in demand, summarized in **Figure 7**, the study identified some areas of concern. Approximately 40 GW PJM's fossil fuel fleet resources may be pressured to retire as load grows into the 2026/2027 Delivery Year. At current low rates of renewable entry, the projected reserve margin would be 15%, as shown in **Table 1**. The projected total capacity from generating resources would not meet projected peak loads, thus requiring the deployment of demand response. By the 2028/2029 Delivery Year and beyond, at Low New Entry scenario levels, projected reserve margins would be 8%, as projected demand response may be insufficient to cover peak demand expectations, unless new entry progresses at a levels exhibited in the High New Entry scenario. This will require the ability to maintain needed existing resources, as well as quickly incentivize and integrate new entry

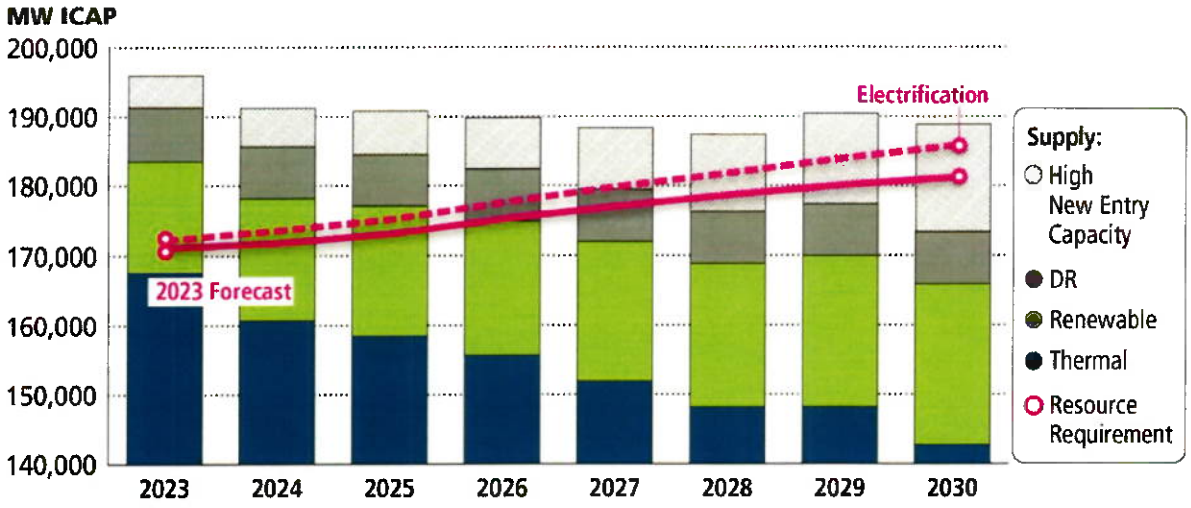
Table 1. Reserve Margin Projections Under Study Scenarios

Reserve Margin	2023	2024	2025	2026	2027	2028	2029	2030
Low New Entry								
2023 Load Forecast	23%	19%	17%	15%	11%	8%	8%	5%
Electrification	22%	18%	16%	13%	10%	7%	6%	3%
High New Entry								
2023 Load Forecast	26%	23%	21%	19%	17%	16%	17%	15%
Electrification	25%	22%	20%	18%	15%	14%	14%	12%

As witnessed during the rapid transition from coal resources to natural gas resources last decade, PJM markets provide incentives for capacity resources. The challenge will be integrating the level of additional resources envisioned to meet this demand, and therefore addressing issues such as resource capacity accreditation is critical in the near term. The low entry rates shown in our Low New Entry scenario are illustrative of recent completion history applied to the current queue. RTO capacity prices in recent auctions have been low for several delivery years, and capacity margins have historically reached around 28% of peak loads. As capacity reserve levels tighten, the markets will clear higher on the VRR curves, sending price signals to build new generation for reliability needs.

The 2024/2025 BRA, which executed in December 2022, highlighted another area of uncertainty. Queue capacity with approved ISAs/WMPAs is currently very high, approximately 35 GW-nameplate, but resources are not progressing into construction. There has only been about 10 GW-nameplate moving to in service in the past three years. There may still be risks to new entry, such as semiconductor supply chain disruptions or pipeline supply restrictions, which are preventing construction despite resources successfully navigating the queue process.

Figure 7. The Balance Sheet



For the first time in recent history, PJM could face decreasing reserve margins, as shown in **Table 1**, should these trends – high load growth, increasing rates of generator retirements, and slower entry of new resources – continue. The amount of generation retirements appears to be more certain than the timely arrival of replacement generation resources, given that the quantity of retirements is codified in various policy objectives, while the impacts to the pace of new entry of the Inflation Reduction Act, post-pandemic supply chain issues, and other externalities are still not fully understood.

The findings of this study highlight the importance of PJM's ongoing stakeholder initiatives (Resource Adequacy Senior Task Force, CAPSTF, Interconnection Process Subcommittee), continued efforts between PJM and state and federal agencies to manage reliability impacts of policies and regulations, and the urgency for coordinated actions to shape the future of resource adequacy.

The potential for an asymmetrical pace within the energy transition, where resource retirements and load growth exceed the pace of new entry, underscores the need for better accreditation, qualification and performance requirements for capacity resources.

The composition and performance characteristics of the resource mix will ultimately determine PJM's ability to maintain the reliability of the bulk electric system. Managing the energy transition through collaborative efforts of PJM stakeholders, state and federal agencies, and consumers will ensure PJM has the tools and resources to maintain reliability.

Attachment II

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STATEMENT

FOR IMMEDIATE RELEASE

PJM Statement on the Newly Issued EPA Greenhouse Gas and Related Regulations

(Valley Forge, PA – May 8, 2024) – PJM provides this statement concerning the EPA rule on New Source Performance Standards for Greenhouse Gas Emissions and the other EPA regulations promulgated on April 25, 2024.

PJM has the responsibility to ensure both short- and longer-term reliability for the 65 million people we serve in a region spanning 13 states plus the District of Columbia. "Reliability" in this context refers both to the day-to-day work of managing the grid to keep the system in balance as well as ensuring that, looking forward, there are adequate resources available and committed to serve the expected demand for electricity in future years.

Because of these unique responsibilities, PJM and other affected RTOs have been extensively involved in EPA rulemakings dating back to the Mercury and Air Toxics Standards rule promulgated on Dec. 16, 2011. Our role in these rulemakings has been to ensure that, in developing proposed environmental rules, EPA has appropriately taken into account the reliability needs of our respective grids.

Consistent with this past level of involvement, PJM worked cooperatively with MISO, SPP and ERCOT (the RTOs most affected by the EPA rule) to craft a set of detailed comments to EPA raising our collective reliability concerns with EPA's initial proposed greenhouse gas (GHG) rule. Our comments and subsequent meetings with EPA were focused on:

- Educating EPA as to the reliability needs of our respective systems and the potential impact that the then-proposed GHG Rule could have on both day-to-day reliability and resource adequacy; and
- Providing to EPA constructive proposals to help mitigate, from a reliability perspective, potential adverse impacts of the then-proposed Rule with a particular focus on ensuring adequate flexibility within the Rule for grid operators to be able to address both short-term reliability issues and resource adequacy within their regions.

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Noting the RTO Comments, in its Final Rule issued on April 24, 2024, EPA made certain adjustments to its initial proposal. Those adjustments altered the resources impacted by the rule and provided additional tools that can help provide flexibility to address reliability issues. PJM is appreciative of EPA's acknowledgment of the importance of the existing resources to reliability, of the need for more flexibility, and its consideration of the Joint RTO Comments. The specific adjustments that were grounded in the Joint RTO Comments and adopted in the Final Rule included:

- **Treatment of Existing Gas Resources** – Removing existing gas from this rulemaking to be addressed holistically in a separate rulemaking
- **State-Specific Compliance Flexibility** – Availability of flexibility for the states to address reliability issues, taking into account the remaining useful life and other factors that affect needed units
- **Averaging** – Allowing unit owners to average their compliance obligations over multiple units to ensure least-cost compliance
- **Emissions Trading** – Authorizing states to utilize allowance trading to minimize compliance costs and burdens
- **Mass-Based Programs** – Authorizing states to potentially utilize an emissions cap rather than controlling the rate of emissions from each affected unit
- **Short-Term Reliability Mechanisms** – Allowing needed units to operate for emergencies without jeopardizing compliance with the rule
- **Timeline Extensions** – Providing extensions for retiring units needed for reliability and units needing more time to install controls, with state discretion for longer periods

PJM's Continuing Reliability Concerns

Although we appreciate EPA's adoption of certain flexibility measures in response to our proposals, areas of concern remain related to ensuring reliability given the impact of the Final EPA Rule:

- The new rules governing both existing coal and new natural gas are premised on EPA's finding that carbon capture and sequestration (CCS) technology represents the "best" system of emissions reduction, which will be commercially available at a reasonable cost. However, the availability of CCS is highly dependent on local topology, such as salt caverns available to sequester carbon and the availability of a pipeline infrastructure to transport carbon emissions from individual generating plants to CCS sites potentially hundreds of miles away. There is very little evidence, other than some limited CSS projects, that this technology and associated transportation infrastructure would be widely available throughout the country in time to meet the compliance deadlines under the Rule.

– MORE –

- The Final Rule imposes the most stringent requirements on new gas and existing coal units that operate as baseload units. Although EPA has focused on these units given that they have greater emissions, these baseload units provide a critical reliability role. We are seeing vastly increased demand as a result of new data center load, electrification of vehicles and increased electric heating load. The future demand for electricity cannot be met simply through renewables given their intermittent nature. Yet in the very years when we are projecting significant increases in the demand for electricity, the Final Rule may work to drive premature retirement of coal units that provide essential reliability services and dissuade new gas resources from coming online. The EPA has not sufficiently reconciled its compliance dates with the need for generation to meet dramatically increasing load demands on the system.

- The Final Rule is premised on the availability of increased access to natural gas infrastructure to support the Rule's "co-firing with gas" compliance option for existing coal units. The present gas pipeline system is largely fully subscribed. Moreover, given local opposition, it has proven extremely difficult to site new pipelines just to meet today's needs, let alone a significantly increased need for natural gas in the future. The Final Rule, which is premised, in part, on the availability of natural gas for co-firing or full conversion, does not sufficiently take into account these limitations on the development of new pipeline infrastructure.

- EPA has left many issues for development in individual state implementation plans. Although this is appropriate and in keeping with the structure of the Clean Air Act, each of the multi-state RTOs like PJM operate a single dispatch. As a result, states will need to coordinate and work closely together to ensure that the individual state plans work well on a regional basis. As a result, the need for regional coordination of individual State Implementation Plans is more important than ever. PJM values its continued collaboration with the other affected RTOs (MISO, SPP and ERCOT) and looks forward to working with the U.S. EPA, individual states and affected stakeholders as this process continues.

PJM Interconnection, founded in 1927, ensures the reliability of the high-voltage electric power system serving 65 million people in all or parts of Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia and the District of Columbia. PJM coordinates and directs the operation of the region's transmission grid, which includes 88,115 miles of transmission lines; administers a competitive wholesale electricity market; and plans regional transmission expansion improvements to maintain grid reliability and relieve congestion. PJM's regional grid and market operations produce annual savings of $3.2 billion to $4 billion. For the latest news about PJM, visit PJM Inside Lines at insidelines.pjm.com.

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EXHIBIT 21

Declaration of Jack Alvey

I, Jack Alvey, declare as follows:

1. I am the President & Chief Executive Officer at Indiana Municipal Power Agency (IMPA). I am over the age of 18 years, and I am competent to testify concerning the matters in this declaration. I have personal knowledge of the facts set forth in this declaration, and if called and sworn as a witness, could and would competently testify to them.

2. I have more than 30 years of experience in electricity generation, and I have been employed at IMPA since 1992. I hold a Bachelor of Science degree from Purdue University, as well as a Master of Business Administration from IU Kelly School of Business.

3. American Public Power Association, of which IMPA is a member, is a member of the Utility Water Act Group ("UWAG"). This declaration is submitted in support of the litigation challenging EPA's final rule entitled *Supplemental Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category*, 89 Fed. Reg. 40,198 (May 9, 2024) ("the Rule").

4. I am familiar with IMPA's operations, including generation and transmission, regulatory compliance, workforce management, and electric markets in general. I also am familiar with how the Rule will affect IMPA as well as its suppliers, members, consumers, and employees.

5. IMPA is a body corporate and politic, and a political subdivision of the State of Indiana. IMPA was created in 1980, under the provisions of Indiana Code § 8-1-2.2, by a group of municipalities for the purpose of jointly financing, developing, owning, and operating electric generation and transmission facilities which are appropriate to the current and projected electric power needs of such municipalities. IMPA became an operating utility in 1983, when it began

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selling electric power to its member utilities under power sales contracts. IMPA owns generation and transmission assets—including assets affected by the ELG Rule—and provides full requirements service to its 61 municipal electric utility members.

6. IMPA remains committed to maintaining a diverse portfolio of generation sources that balances affordability, reliability, and environmental responsibility. IMPA's generation portfolio includes both fossil fuel-fired and renewable generating resources. IMPA serves its members with power generated from a diverse portfolio of assets which includes coal, natural gas, solar, and wind energy.

7. IMPA owns or receives power from multiple electric generating units ("affected EGUs") that are subject to the Rule and thus must comply with the Rule's stringent new standards for steam electric units. Two of these affected EGUs, located at Trimble County Generating Station, have remaining useful lives that may be significantly shortened under the Rule—and will, at minimum, incur substantial compliance costs. As a not-for-profit entity, such costs will be passed directly to our members, and the customers in their service territories. The table below identifies the key coal-fired EGUs partially owned by IMPA that will be negatively impacted if the Rule takes effect.

Affected EGU	State	Cost of Compliance with 2020 Rule
Trimble County Generating Station	KY	Trimble County Generating Station incurred more than $67M in compliance costs in order to satisfy the 2020 ELG Rule. Compliance costs for facilities that will satisfy the new ELG Rule are expected to significantly exceed this figure. Moreover, the investment incurred to satisfy the 2020 Rule will be useless by the new requirements.

Impact of the Rule on IMPA

8. IMPA relies on the affected EGUs to reliably serve load in MISO. The Rule could have a substantial effect on the future viability of affected EGUs and will, at minimum, incur substantial compliance costs. These costs will be incurred in addition to the substantial costs resulting from the imposition of the 2020 ELG Rule, which this Rule replaces. Accordingly, IMPA will need to recover costs for both the now-obsolete control measures required under the 2020 Rule and the new control measures required under the new Rule. These impacts will ultimately be felt by the consumers in our members' service territories – all of whom depend on reliable generation to power their homes.

Impacts at Trimble County Generating Station

9. Trimble County has 2 affected EGUs that can generate more than 1200 MW. Discharges from the Trimble County Station are managed in compliance with a Kentucky Pollution Discharge Elimination System (KPDES) permit with an effective date of July 1, 2023. The KPDES permit includes proactive and as-soon-as-possible compliance requirements for the 2020 ELG Rule – incorporating FGD Waste Water limits based on the operation of physical, chemical, biological, and ultrafiltration treatment equipment. The biological treatment is currently in the commissioning phase. Aside from FGD Waste Water, the KPDES addresses surface water runoff (rainfall), cooling tower blow-down, floor drains, landfill leachate, and domestic sanitary wastewater —each are controlled, permitted discharges to the Ohio River. Trimble County converted to and utilizes under-boiler drag chain conveyors which do not use Bottom Ash Transfer Water.

10. Trimble County Generating Station took substantial steps to comply with the 2020 Rule, including capital investments of over $67M to install a biological and ultrafiltration systems. These irreversible steps (or reversible with exorbitant costs) have resulted in appreciable costs to IMPA ratepayers. The 2024 Rule would have an even greater cost impact and would obviate the need for the assets constructed in response to the previous Rule.

11. Trimble County's remaining depreciable life is indefinite, as no specific retirement date has been set. Both units have a long horizon of remaining useful life and provide a valuable service to IMPA and the customers within its footprint.

12. The full extent of the cost of compliance with the new Rule is difficult to calculate for both Trimble EGUs, and such methods and costs continue to be evaluated. The Rule allows affected EGUs to remain in operation beyond 2034 only if they can achieve zero discharge of FGDW and Combustion Residual Leachate (CRL) as soon as possible after July 8, 2024 but no later than December 31, 2029. Installing zero discharge FGDW and CRL treatment technology is an incredibly burdensome standard for units of this type, if it is attainable at all before the 2029 deadline.

13. In combination with EPA's final rules governing greenhouse gas emissions, CCR impoundments, and others, the ELG Rule contributes to the tide of burdensome regulations that put the viability of even the newest coal-fired facilities at risk. Without relief, closure well in advance of the remaining useful life of many EGUs is a significant risk.

14. To meet the Rule's deadline for these retirements, IMPA—along with its co-owners—must immediately begin spending money across several expense categories.

15. Yet these assumptions reflect only *current* market dynamics. They are very likely to change for the worse once EGUs across the region and the Nation are contemporaneously

turning to the market for replacement power and are turning to equipment manufacturers for new equipment because of the impacts of the Rule on all affected EGUs, not just IMPA's.

16. If the Rule takes effect, electric markets will be further constrained, as generators across the country will see reductions in their portfolios of reliable, dispatchable generation. Coal-fired power plants currently produce about 20% of the United States electric supply. This generation will be largely eliminated by 2034 under this Rule—in combination with others—due to their unrealistic and unavailable compliance options. Depending on the results of portfolio modelling and other studies that the industry will need to conduct now that the Rule has been issued, IMPA will need to construct at least some new generation to compensate for potential retirements if Trimble County Generating Station is forced to cease operations.

17. IMPA cannot depend solely on intermittent resources and battery backups for baseload generation. Given the problems with intermittent generation associated with its non-dispatchable (*i.e.*, non-controllable) nature, IMPA will likely have to look to other generation sources to attempt to provide replacement generation for any baseload power that it loses because of the Rule.

18. The only technically viable option in the short-term under the Rule to replace baseload, dispatchable coal-fired generation (apart from nuclear) is to utilize natural gas. One option is to convert the coal boilers to natural gas steam generating units, although doing so would subject them to the GHG Rule's not commercially proven or available 90% carbon capture and sequestration requirements. The second option is to transition to combustion turbine technology, either using a large number of low-capacity factor simple-cycle combustion turbines (CTs) all running at a capacity factor of 20% or less or a more expensive combined-cycle plant limited to a 40% capacity factor. The natural gas approach would depend on a fuel supply (gas)

that is subject to high price volatility, together with market purchases and/or renewables during the many hours that CTs would not be permitted to run given their low capacity factors.

19. IMPA projects that this Rule will exacerbate the current trend toward capacity shortfalls throughout the country—particularly in the Midwest, where coal-fired generation comprises a higher percentage of the overall generation mix. Higher prices and greater volatility will likely result.

20. *Stranded costs*. IMPA and its co-owners spent approximately $67 million to install wastewater treatment technology to comply with the 2020 ELG Rule. The new Rule requires that facilities install by 2029 completely new and different technologies from those required for 2020 ELG Rule compliance, making the 2020 ELG investments wasted and stranded investments. Those equipment upgrades are installed and being commissioned in the case of Trimble County Generating Station.

21. IMPA estimates that the cost of compliance with the new Rule at Trimble County will greatly exceed the costs incurred by the 2020 Rule.

22. Given the substantial new investments required to be made by the Rule, which may not be placed into service until as late as 2029, and the substantial wasted and stranded investments made in compliance with the 2020 ELG Rule, if the Rule is not stayed, there is significant risk that IMPA and many other owners of affected EGUs otherwise planning to operate past 2034 will make the election, provided by the Rule, to issue a NOPP and commit to retire the affected EGUs by the end of 2034 so as to allow such EGUs to operate at least until the end of 2034, rather than the end of 2029, which would be the longest that affected EGUs would be permitted to operate under the Rule without making substantial new investments.

23. On the other hand, if IMPA or any other affected EGU makes the decision to comply with the Rule while it and the GHG Rule are under appeal for the next several years, the EGU would need to start spending money immediately on the investments required to comply with the ELG Rule by its 2029 compliance date, and thereby risk having those investments become uneconomic and stranded investments if either rule is overturned.

24. EPA finalized the Rule at the same time as the GHG Rule, as part of a coordinated and inter-related suite of four new rules affecting power plant air emissions, water discharges, and solid waste disposal.

25. Without having the Rule stayed and fully adjudicated and overturned by the end of 2025, IMPA and many other affected EGUs otherwise planning to operate after 2034 will be faced with the prospect of making uneconomic environmental expenditures to comply with the Rule, with no assurance that compliance with the Rule by 2029 would even be possible, or making a retirement commitment through the issuance of a NOPP by the end of 2025, with no assurance that reliable replacement sources will be available by 2034.

26. In IMPA's view, the combined effect of the Rule, the GHG Rule, and other recent actions by EPA is designed to pressure affected EGUs to make binding commitments to retire, whether by 2025 under the Rule, and/or by 2026 under the GHG Rule, by forcing the affected EGUs to make uneconomic or technically impossible investments required under the rules, should the rules ultimately be upheld, or obtain relief from the rules (to the end of 2031 in the case of the GHG Rule, and to 2034 in the case of the Rule) but only if binding commitments to retire are made during the limited window of time while the rules are still under appeal and regulatory uncertainty prevails. For this reason, and given the combined effect of EPA's actions, it is imperative that both the Rule and the GHG Rule be stayed.

27. *Increased Labor, Procurement, Financing, and Fuel Supply Costs*. As a result of the Rule, EGUs may be required in 2025 to make a binding commitment to retire by no later than the end of 2034. And all coal-fired units in the country will be required to make compliance decisions resulting from the Rule, many of which are also likely to make the determination that retirement by the end of 2034 is the only viable compliance option. When this binding commitment is made, almost certainly before the Rule has made its way through the appeals process, this commitment is likely to have negative and immediate effects on labor, procurement, financing, and fuel supply costs.

28. Shutting down otherwise viable coal-fired facilities will result in scores of lost jobs. In addition to causing significant disruptions to local communities, personnel, and their families, the mandatory nature of these reductions may also increase the cost of labor in the near term as workers retire or shift away from the industry. Labor costs may be higher for positions that are due to be eliminated.

Absent a Stay, IMPA Will Suffer Immediate Irreparable Harm

29. *Immediate replacement power costs*. In combination with the torrent of other new regulations imposed in recent years, the Rule will likely require IMPA to secure replacement power as a result of forced early retirements. There are only two options for replacement power. The first option is to build new generation. If IMPA decides that it must replace the retired generation with other owned or controlled generation, then it will incur immediate costs to begin the design, planning, site selection and acquisition, equipment procurement, construction, contracting, permitting, financing, fuel supply, and other processes associated with building or acquiring new generation.

30. Given that many existing generators are likely to also be forced into retirement before 2034, much new replacement generation will be required across the country, resulting in cost increases and delays for all new generation projects. Planning and execution will need to begin immediately for such replacement generation to be in service before 2034.

31. The second option is to purchase power from the market. But power markets are highly volatile, which exposes IMPA and its customers to large price swings and counterparty risk. If other power generators turn to the market all at once, that volatility will only become more pronounced. Planning for and attempting to mitigate the effects of this volatility has its own costs, such as developing and implementing a hedging strategy and plan. No matter what compliance path is chosen, the costs of replacement power will begin to accrue immediately.

32. *Immediate planning costs*. As mentioned above, as a result of the Rule (and companion GHG Rule), IMPA will immediately begin incurring costs to model its portfolio without the affected EGUs, and to evaluate how best to replace that power supply whether that be from the market or replacement generation, or some combination of both.

33. In the absence of a stay, if IMPA and its co-owners choose by the end of 2025 to file a NOPP and commit to retire Affected EGUs by 2034 (as a result of uncertainty about the outcome of litigation over this Rule and the GHG Rule), then even if the rules are ultimately overturned, such relief will be illusory, as Affected EGUs will have already made a commitment in 2025 to retire such facilities by 2034.

34. *Immediate costs to IMPA's members.* All of these near-term costs will begin flowing to municipal customers.

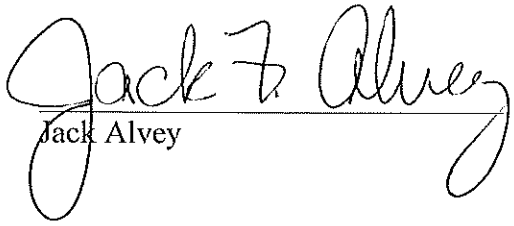
35. These costs are not reversible. Equipment generally cannot be returned without cost. Dollars spent on portfolio modeling, generating facility design, planning, permitting,

engineering, site selection and acquisition, fuel procurement, financing and other studies and costs cannot be refunded. Legally binding retirement promises generally cannot be undone. IMPA might even be forced into a retirement decision earlier than what is required under the Rule, if a major capital expenditure is required that could not be justified given the before-2034 retirement date.

36. In sum, if the Rule remains in effect while this litigation is pending, IMPA and its co-owners in Trimble County Generating Station will have no choice but to incur significant unrecoverable compliance costs as well as to shoulder the many other substantial, immediate, and irreparable harms described above.

I declare under penalty of perjury under the laws of the United States of America, pursuant to 28 U.S.C. § 1746, that the foregoing is true and correct to the best of my knowledge.

Executed on this 9th day of July, 2024, in Carmel, Indiana.



Jack Alvey

EXHIBIT 22

DECLARATION OF HEATH LOVELL

1. I am the President of Hallador Power Company, LLC ("Hallador"), which is a wholly owned subsidiary of Hallador Energy Company. I am over the age of 18 years, and I am competent to testify concerning the matters in this declaration. I have personal knowledge of the facts set forth in this declaration, and if called and sworn as a witness, could and would competently testify to them.

2. I graduated with a Master of Business Administration and a Bachelor of Science degree in Electrical Engineering from the University of Kentucky. I have over 25 years of experience in the energy industry.

3. Hallador is a member of America's Power, and this declaration is submitted in support of America's Power's motion to stay pending judicial review the EPA final rule entitled "Supplemental Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category," 89 Fed. Reg. 40,198 (May 9, 2024) (hereinafter the "2024 Rule").

4. In October 2022, Hallador purchased the Merom Generating Station ("Merom"). Merom has two units that are affected by the 2024 Rule, Unit 1 and Unit 2, each of which has a nameplate capacity of 540 megawatts. Merom is located in Sullivan County, Indiana, and began operation in 1982.

5. When Hallador purchased Merom in October 2022, EPA's rule entitled "Steam Electric Reconsideration Rule," 85 Fed. Reg. 64,650 (Oct. 13,

2020) (hereinafter the "2020 Rule"), was in effect. Hallador was aware that it would need to install treatment technology at Merom no later than December 31, 2025, to comply with the 2020 Rule. Hallador estimates that compliance with the 2020 Rule at Merom will cost approximately $20 million once it is complete.

6. When EPA proposed the 2024 Rule in March of 2023, it proposed chemical precipitation as the technology basis (Best Available Technology Economically Achievable or "BAT") for establishing effluent limitations to control pollutants discharged in combustion residual leachate ("CRL"). 88 Fed. Reg. 18,824, 18,848 (Mar. 29, 2023); *see also id.* at 18,838 & Table VII-1 ("Under all four options [for CRL], EPA proposes to establish BAT limitations … based on chemical precipitation treatment."); *id.* at 18,885 ("EPA is proposing limitations on [CRL] based on chemical precipitation".). Although Hallador would have to add chemical precipitation treatment at Merom, it was not overly concerned with the proposed rule.

7. When EPA released the final 2024 Rule, Hallador was shocked to see that it included a zero-discharge requirement for CRL. Although the proposed rule "solicit[ed] comment on whether the technology basis for BAT limitations to control discharges of pollutants in CRL should be based on more stringent technology, such as biological treatment, spray dry evaporation, thermal systems, or membrane filtration," this did not seem like a serious consideration given that

the entire discussion of technologies more stringent than chemical precipitation was less than one page, and the discussion of each of these technologies was a paragraph at most—and in the case of spray dry evaporation, nonexistent. *See id.* at 18,849.

8. The 2024 Rule's zero-discharge requirement for CRL renders much of the $20 million worth of technology that Hallador is installing to comply with the 2020 Rule superfluous. The technology required at Merom by the 2024 Rule for CRL would satisfy the requirements of the 2020 Rule. But Hallador cannot simply rely on installation of the technology required to comply with the 2024 Rule and forgo the technology it is installing to comply with the 2020 Rule because the technology needed to comply with the CRL requirements of the 2024 Rule cannot be installed by December 31, 2025—the deadline for compliance with the 2020 Rule.

9. This means that Hallador must expend $20 million to comply with the 2020 Rule and then immediately turn around and spend *another* estimated $20 million to comply with the 2024 Rule, even though the technology for the 2024 Rule alone would satisfy the conditions of both rules.

10. The 2024 Rule renders much of the technology system Hallador is installing to comply with the 2020 Rule by December 31, 2025, a stranded asset. Once Hallador installs the technology system needed for the 2024 Rule, which is

required to be done within four years of the compliance deadline for the 2020 Rule (i.e., by December 31, 2029), much of the technology system for the 2020 Rule will be superfluous.

11. If a stay of the 2024 Rule is not provided during judicial review, Hallador will suffer irreparable harm because it will immediately need to begin preparations to comply with the 2024 Rule. Hallador expects that it will spend approximately $100,000 in the next few months, and approximately $2 million over the next two years—within the expected timeframe for litigation over the 2024 Rule. These funds cannot be unspent.

12. In addition, Hallador is a merchant generator, not a regulated utility. As a result, the impact of these immediate costs during the pendency of the litigation on Hallador is exacerbated. As a merchant generator, Hallador sells electricity on the competitive, spot and day-ahead markets. Unlike regulated utilities, which can recover capital costs through rate processes, merchant generators' revenues generally do not cover capital costs, including for pollution control equipment. This is because when there is adequate or excess capacity on the market, the price of electricity gets driven down to the variable cost of production, which is a fraction of the all-in cost that includes capital expenses.

13. Because Hallador is a merchant generator, it may never recover the $2 million it expects to pay to prepare to comply with the 2024 Rule during the

pendency of the litigation. Before it expends these sums, it should know that it is doing so to comply with a lawful rule.

14. In addition, the National Pollutant Discharge Elimination System ("NPDES") permit for Merom is due for renewal soon, and Hallador will have to submit its permit application by July 2025, and a new permit will be issued by January 2026. If the 2024 Rule is not stayed, its provisions, including the zero-discharge requirement for CRL, will have to be included in the Merom NPDES permit unless the litigation concludes beforehand (which is highly unlikely). Once the zero-discharge requirement for CRL is included in Merom's NPDES permit, Hallador must comply with it—even if the 2024 Rule later gets vacated—unless and until it goes through a difficult process to remove the requirement from the permit. This also will cause irreparable harm to Hallador.

15. For all of these reasons, Hallador will suffer irreparable harm if the 2024 Rule is not stayed during judicial review.

I declare under penalty of perjury under the laws of the United States of America, pursuant to 28 U.S.C. § 1746, that the foregoing is true and correct to the best of my knowledge.

Dated: July 26, 2024

Heath Lovell

Heath Lovell

EXHIBIT 23

IN THE UNITED STATES COURT OF APPEALS
FOR THE EIGHTH CIRCUIT

STATE OF WEST VIRGINIA, STATE OF GEORGIA, STATE OF ALASKA, STATE OF ARKANSAS, STATE OF IDAHO, STATE OF INDIANA, STATE OF IOWA, STATE OF KANSAS, COMMONWEALTH OF KENTUCKY, STATE OF LOUISIANA, STATE OF MISSISSIPPI, STATE OF MISSOURI, STATE OF MONTANA, STATE OF NEBRASKA, STATE OF OHIO, STATE OF OKLAHOMA, STATE OF SOUTH CAROLINA, STATE OF TENNESSEE, STATE OF TEXAS, STATE OF UTAH, COMMONWEALTH OF VIRGINIA, AND STATE OF WYOMING, *Petitioners*, v. UNITED STATES ENVIRONMENTAL PROTECTION AGENCY; MICHAEL S. REGAN, Administrator of the United States Environmental Protection Agency, *Respondents*.	Case No. 24-2225

DECLARATION OF JAMES F. HUSTON
IN SUPPORT OF PETITIONERS' MOTION TO STAY FINAL RULE

I, James F. Huston, make the following declaration pursuant to 28 U.S.C. § 1746 and state under penalty of perjury that the following is true and correct to the

best of my knowledge and is based on my personal knowledge or information available to me in the performance of my official duties:

1. My name is James F. Huston, and my business address is 101 W. Washington St., Suite 1500 E, Indianapolis, Indiana, 46204. I am over the age of 18, have personal knowledge of the subject matter, and am competent to testify concerning the matters in this declaration.

2. I have served as Chairman of Indiana Utility Regulatory Commission (IURC) since March 2018 and served as a Commissioner since November 2014. I also serve on the National Association of Regulatory Utility Commissioners (NARUC) Committee on Gas and on the Gas Technology Institute's Public Interest Advisory Committee. I was recently appointed to the Member Representatives Committee of the North American Electric Reliability Corporation (NERC) and the NARUC/Federal Energy Regulatory Commission (FERC) Collaborative. I earned my Bachelor of Science and Master of Arts degrees from Ball State University.

3. The IURC is responsible for ensuring safe and reliable service at just and reasonable rates for the utilities it regulates, including electric utilities, serving retail customers in Indiana. As Chairman and a member of the IURC, I have responsibility over proceedings before the IURC, working with staff in reviewing the evidence presented, and making determinations based on the

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applicable laws and the public interest, as well as establishing rules and guidelines requiring appropriate short-term and long-term planning. Because of the potential impact on resource reliability and retail rates, IURC Commissioners and staff also review and participate in the stakeholder processes of the two regional transmission organizations ("RTOs") that have Indiana electric utilities as members, the Mid-continent Independent System Operator, Inc. ("MISO") and the PJM Interconnection, LLC ("PJM"), and in the related regional state committees, the Organization of MISO States ("OMS") and the Organization of PJM States, Inc. ("OPSI"). In addition, the IURC monitors filings affecting Indiana utilities and intervenes and provides comments to the Federal Energy Regulatory Commission ("FERC").

4. I am submitting this declaration in support of Petitioners' Motion to Stay the Final Rule published by the U.S. Environmental Protection Agency (EPA) on May 9, 2024, entitled "Supplemental Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category," 89 Fed. Reg. 40198.

5. Continued reliability of the electric generation systems must be an important consideration as the U.S. EPA moves forward with this rule. The Indiana General Assembly established a balanced approach to electric generation regulatory decisions in Indiana Code section 8-1-2-0.6, which declares that it

is the continuing policy of the State of Indiana "that decisions concerning Indiana's electric generation resource mix, energy infrastructure, and electric service ratemaking constructs must consider" the following attributes (commonly referenced as the "Five Pillars"):

a. Reliability,

b. Affordability,

c. Resiliency,

d. Stability, and

e. Environmental sustainability

6. While the U.S. EPA's main concern is environmental and climate, the elimination of too much electric generation too quickly may cause massive issues, affecting the other key attributes needed for electric generation and the affordability of electricity generally.

7. As Chairman, I have concerns that the Final Rule will undermine the reliability and resiliency of the electric grids upon which the State of Indiana and its citizens rely and could result in significantly higher prices for electricity in Indiana.

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The Final Rule Threatens an Already Vulnerable Power Grid

8. The power grids providing electricity to Indiana are already stretched thin and do not have the resiliency or the buffer of dispatchable generation that they had ten or even five years ago.

9. MISO's reserve margins "have been exhausted through load growth and unit retirements," and the entire region could experience a 4.7 GW shortfall beginning in 2028 if "currently expected generator requirements actually occur." And this shortfall, caused in part by early retirements of Electric Generating Units (EGUs), could compromise grid reliability. MISO's Response to the Reliability Imperative, 6, 11–12, (updated February 2024), https://cdn.misoenergy.org/2024%20Reliability%20Imperative%20report%20Feb.%2021%20Final504018.pdf?v=20240221104216.

10. PJM recently warned of capacity deficiencies and reliability degradation as dispatchable thermal plants are retired prematurely. In a February 2023 report on the risks relating to energy resource transitions that a movement away from base load dispatchable generation will cause PJM stated:

> The composition of the PJM Interconnection Queue has evolved significantly in recent years, primarily increasing in the amount of renewables, storage, and hybrid resources and decreasing in the amount of natural gas-fired resources entering the queue . . .
>
> By the 2028/2029 Delivery Year and beyond, at Low New Entry scenario levels, projected reserve margins would be 8%, as projected demand response may be insufficient to cover peak

> demand expectations, unless new entry progresses at levels exhibited in the High New Entry scenario. This will require the ability to maintain needed existing resources, as well as quickly incentivize and integrate new entry. . .
>
> Thermal generators are retiring at a rapid pace due to government and private sector policies as well as economics . . .
>
> PJM' s interconnection queue is composed primarily of intermittent and limited-duration resources. Given the operating characteristics of these resources, we need multiple megawatts of these resources to replace 1 MW of thermal generation.

Energy Transition in PJM· Resource Retirements & Replacements & Risks, 1, 10, 16 (Feb. 24, 2023), https://bit.ly/3DOBR1P.

11. These power grids are interdependent, so a reduction in EGUs anywhere in the RTOs to which Indiana belongs will likely affect all members.

12. If the Final Rule forces even more coal generation sources to shut down prematurely or run less frequently, it could impact grid reliability and the provision of reliable electricity to the people of Indiana and all MISO and PJM member regions.

13. The EPA data, which shows a projected growth in renewable resources over the next two decades, will not be enough to reliably meet the projected growth in demand, especially if existing dispatchable fossil fuel generation is forced into early retirement by this Final Rule or other federal rules.

14. Dispatchable energy is energy that is available on demand and that can be increased or decreased to maintain balance in the interconnected alternating

current electrical system. Energy sources such as wind and solar are considered non-dispatchable. Even when these non-dispatchable resources exceed the immediate demand for electricity, without dispatchable resources running to take up the slack in wind and solar generation when the wind decreases, even momentarily, or skies cloud up in the middle of the day, the electric system will become unstable and unreliable.

15. The Final Rule may cause coal plants in the MISO and PJM grids to close. Given the current regulatory landscape, MISO and PJM will have to move towards even more intermittent resources, such as wind or solar, and will need more online reserve resources to provide the constant balance of supply to load when wind and solar resources are intermittent; that is, when the wind is not blowing (or blowing unevenly) or the sun is not shining (or shining unevenly). Both MISO's and PJM's generation interconnection queues are overloaded and backlogged, so getting sufficient generation interconnected in time is also an issue.

Impact of the Final Rule on Indiana's Electricity Pricing

16. Indiana has a diverse portfolio of power generation resources, including wind, coal, solar, hydroelectric, natural gas, and nuclear power[1]. Once accounting

[1] Cook Nuclear Plant in Michigan.

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for more than 90% of Indiana's electricity, coal-fired electricity generation is now less than half of the State's total energy generation. Electricity prices have risen in Indiana, changing Indiana's ranking from the 4th lowest in prices in 2002 to 29th lowest in 2022, according to the U.S. Energy Information Administration. This shift is largely a result of the bombardment of EPA mandates.

17. The Rule will affect the price of electricity in Indiana. If a stay is not granted, Indiana's existing coal-fired power plants will have to comply with the more stringent requirements, which could result in running the plants less, particularly during high temperatures in the summer when electricity is often needed the most. As a result, the utilities owning those plants will need to purchase additional electricity.

18. The costs for these additional electricity purchases are passed on to consumers through rate changes for cost recovery as required by law.

Executed in Indianapolis, Indiana, on July 23, 2024.

James F. Huston
Chairman
Indiana Utility Regulatory Commission

EXHIBIT 24

UNITED STATES COURT OF APPEALS
FOR THE EIGHTH CIRCUIT

SOUTHWESTERN ELECTRICAL POWER COMPANY, *et al.,*

Plaintiffs

v.

No. 24-2123
(and consolidated cases)

U.S. ENVIRONMENTAL PROTECTION AGENCY and MICHAEL REGAN

Defendants

DECLARATION OF R. BRUCE SCOTT

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1) I, R. Bruce Scott, formerly served as the Deputy Secretary of the Kentucky Energy and Environment Cabinet from 2016 through 2019 and as Commissioner of the Kentucky Department for Environmental Protection from 2008 to 2016. I currently work as an Independent Contractor providing consulting services to clients, often with environmental regulatory challenges in the water sector. In my prior capacities, I was responsible for direct oversight and implementation of many programs, including the Clean Water Act ("CWA") section 402 National Pollutant Discharge Elimination System (NPDES) in Kentucky. I have extensive experience working with the NPDES program including the Steam Electric Power Generating Point Source Category Effluent Guideline (ELG). Based on my work, I have the personal knowledge and experience to understand the impacts of the Environmental Protection Agency's (EPA's) final rule establishing technology-based effluent limitations guidelines and

standards (ELGs) for the steam electric power generating point source category. 89 Fed. Reg. 40198 (published May 9, 2024, effective July 8, 2024) ("ELG Rule").

2) Kentucky coal-fired units accounted for 69% of electricity generated in Kentucky in 2020, a significant decrease from the prior year. Kentucky Office of Energy Policy (OEP) 2023 Kentucky Energy Profile at 16, available at https://eec.ky.gov/Energy/KY%20Energy%20Profile/Kentucky%20Energy%20Profile%202023.pdf. According to OEP's interactive maps, Kentucky currently has 11,346 MW of installed coal generating capacity located at 8 different power plants (with multiple units), representing approximately 54% of Kentucky's total installed generating capacity. *See* Kentucky OEP, *Power Plants*, available at https://kcewsreports.ky.gov/t/OEP/views/PowerPlantProfilesDashboard/P3D?%3Aembed=y&%3AisGuestRedirectFromVizportal=y (last accessed July 22, 2024). Kentucky has experienced a substantial decline in coal-fired electricity generation that began during the Obama Administration, when environmental regulations and other factors resulted in a rapid transition in Kentucky from coal to natural gas. *See* 2023 Kentucky Energy Profile at 16.

3) The federal Effluent Limitations Guidelines and Standards (ELGs) for the Steam Electric Power Generating Category were initially established in 1982. The ELG was subsequently revised in 2015, 2020, 2023, and 2025. This accelerated flurry of ELG revision activity has resulted in extensive litigation, increased costs, and uncertainty for states, ratepayers and affected power plants. Combined with other factors, including a wide array of environmental regulations, the result has been a significant decrease in coal-fired electricity generation.

4) The 2025 ELG Rule establishes new requirements for a subset of wastewaters that conflicts with remedies that power plants are already in the process of implementing in response to the earlier ELG rules, potentially subjecting those remedies costing hundreds of millions of dollars

at a given power plants to becoming stranded or lost costs. For example, Kentucky entities LG&E and KU have spent the past several years installing new systems at the projected compliance cost of $283 million. *See* Comments of LG&E and KU Energy, Docket No. EPA-HQ-OW-2009-0819 at 2 (May 30, 2023). Those costs "will be borne by the companies' electric customers." *Id.* But as those measures near completion, LG&E and KU must now implement "substantial additional controls" that "could render significant portions of their past compliance investment obsolete." *Id.* at 3. This subsequently results in ratepayers unnecessarily being subjected to additional, substantial costs.

5) In addition, this unnecessary confusion subjects understaffed state regulatory agencies and power plants to confusing and protracted NPDES permitting processes, which will begin immediately.

6) EPA carefully attempts to justify the ELG Rule by arguing that it will lead to minimal costs. The following statement is provided from the preamble:

> The EPA analyzed the final rule (Option B) using IPM [a comprehensive electricity market optimization model] to further inform the Agency's understanding of the potential impacts of the ELGs. The base case used for this analysis, which the EPA was developed using IPM Version 6, embeds an energy demand forecast that is derived from DOE's "Annual Energy Outlook 2023." The base case also includes the effects of the [Inflation Reduction Act] provisions reflecting supply-side impacts, final Federal rules (e.g., 2020 ELG rule, CSAPR and CSAPR Update, 2012 MATS rule, the 2014 CWA section 316(b) rule, and 2015 CCR rule and CCR Part A rule), and state rules and programs such as the Regional Greenhouse Gas Initiative, California's Global Warming Solutions Act, and state-level Renewable Portfolio Standards policies.

89 Fed. Reg. at 40264.

EPA's modelling analysis concludes:

Table VIII-2. Estimated Impact of the Final Rule (Option B) on Steam Electric Power Plants as a Group in the Year 2035

Metric	Baseline Value	Change Attributable to the Final Rule as Compared to the Baseline	
		Value	Percent
Total capacity (MW)	220,237	-5,782	-2.6%
Early retirement or closure (MW)	104,544	5,782	5.5%
Early retirement or closure (number of plants)	78	5	6.4%
Total generation (GWh)	789,529	-23,579	-3.0%
Average variable production cost (2023$/MWh)	$20.18	-$0.21	-1.1%
Annual cost (million 2023$)	$28,580	-$840	-2.9%

MW = megawatt; MWh = megawatt-hour; GWh = gigawatt-hour = 1,000 MWh

> Under the final rule, generation at steam electric power plants is projected to decrease by 23,579 GWh (3.0 percent) nationally when compared to baseline. IPM projects a net decline in total steam electric capacity by 5,782 MW (approximately 2.6 percent of total baseline steam electric capacity) due to early retirement attributable to this final rule. Five additional plants are projected to retire early under the final rule when compared to baseline. These incremental early retirements represent a 6.4 percent increase relative to projected baseline plant retirements, but only represent 0.7 percent of the total 688 steam electric power plants modeled in IPM. See section 5.2.2.2 in the RIA for details.

89 Fed. Reg. at 40265. The reader must understand modelling, EPA rules, and energy production to appreciate what EPA is saying. EPA states that the additional or "incremental early retirements" from the ELG Rule will represent a 6.4 percent increase in steam electric power plant retirements from the projected baseline or base case plant retirements, which EPA subsequently dismisses by saying this is only 0.7 percent of the total "steam electric power plants" modelled in IPM.

The reader must interpret from the table that the "base case" assumes 78 plants are or will be retired because of other EPA rulemakings, and this isn't an inclusive list of other, more draconian, recent EPA rulemakings. In essence, EPA is arguing that an additional 5 coal-fired power plants retiring due to the ELG Rule is inconsequential when compared to the

cumulative number of other plants that retired or are retiring because of other EPA rules. EPA is proving the point that they are enforcing energy policy via EPA rulemaking. EPA, via its own modelling, is forcing or has forced the early retirement of approximately 110,000 MW of steam electric-generating capacity, or approximately 50% of the total steam electric generating capacity illustrated in this EPA analysis.

7) As a part of all federal EPA rulemakings, an evaluation regarding Environmental Justice (EJ) must be conducted. EPA states the following in the preamble:

> Costs of the final rule in terms of electricity price increases among residential households may impact low-income households and households of color more relative to all households as low-income households and households of color tend to spend a greater proportion of their income on energy expenditures. Despite this, the potential price increases under the upper bound cost scenario represent between less than 0.1 percent and 0.2 percent of energy expenditures for all income, race groups, and income quintiles, and therefore the EPA does not expect costs to have a substantial impact on low-income households and households of color.

89 Fed. Reg. at 40277. EPA's review of potential EJ impacts on costs concludes that cost increases due to the ELG Rule and the early retirement of coal-fired power plants is not substantial on low-income households and households of color. EPA fails to recognize that Kentucky is home to some of the poorest counties in the nation who have already experienced dramatic increases in electricity costs due to stranded assets because of early retirement of coal-fired power plants attributable to EPA rulemakings. EPA is wrong in this EJ conclusion. A small increase on an already substantially increased and unaffordable cost is not insignificant.

8) I declare under penalty of perjury pursuant to 28 U.S.C. § 1746 that the foregoing is true and correct. Executed on this 23rd day of July, 2024, at Frankfort, Kentucky.



R. Bruce Scott

EXHIBIT 25

COMMISSIONERS:

JASON SHAW, Chairman
TIM G. ECHOLS, Vice-Chairman
FITZ JOHNSON
LAUREN "BUBBA" McDONALD
TRICIA PRIDEMORE

REECE McALISTER
EXECUTIVE DIRECTOR

SALLIE TANNER
EXECUTIVE SECRETARY

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In RE: United States Environmental Protection Agency (EPA) "Supplemental Effluent Limitations Guidelines (ELG) and Standards for Steam Electric Power Generating Point Source Category" 89 Fed. Reg. 40198 (May 9, 2024)

COMMISSION RESOLUTION IN SUPPORT OF A STAY MOTION ON EPA's NEW DIRECTIVES ON ELG

WHEREAS the May 2024 directives from the EPA on Effluent Limitation Guidelines are the second time the EPA has released new directives on this topic in the past four years.

WHEREAS electricity is a vital component of modern American life, and Georgia electric customers are already bearing the costs of the last ELG rules from the EPA.

WHEREAS Georgia electric utility customers have more than $15/month on their electric bills just to pay the costs of EPA regulations such as the last EPA ELG directive.

WHEREAS EPA changing ELG directives this soon, customers will have to eat the costs of meeting the prior and the new directives. With no end in sight to the cost increases from these and other EPA directives, Georgia customers are suffering. Just through 2022, Americans have invested over $127 billion in emission controls on the coal fleet.

WHEREAS the new technologies proposed in the 2024 EPA ELG directive are novel and not yet available on the open market. Additionally, the 2024 EPA ELG directive does not account for the extraordinarily huge costs of deploying these new technologies and the cost burden inflicted upon American electricity customers.

WHEREAS this new EPA action, sidesteps the United States Congress and attempts to force the closure of America's coal generating electricity fleet through red-tape, fines, penalties, fees and backdoor taxes, all the while American coal exports totaled a record 100 million tons in 2023.

WHEREAS the Georgia Public Service Commission passed an interim Integrated Resource Plan in April 2024 authorizing the state's largest electric utility to procure over 7,000mW of new electric generation to meet the needs of our fast growing state and assist America in being a leader in established global technology deployment. This IRP includes renewables plus batteries, but also relies upon the existing diversified portfolio of electricity generation to meet customer needs.

BE IT RESOLVED the statewide-elected members of the Georgia Public Service Commission support a motion to stay the EPA ELG directive of May 9, 2024.

Jason Shaw
Chairman

Tim G. Echols
Vice-Chairman

Fitz Johnson
Commissioner

Lauren "Bubba" McDonald
Commissioner

Tricia Pridemore
Commissioner

7/24/24
Date