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U.S. Environmental Protection Agency
EPA Docket Center (EPA/DC)
Office of Water Docket
Mail Code 28221T
1200 Pennsylvania Avenue NW
Washington, DC 20460

Attn: Docket ID No. EPA-HQ-OAR-2023-0072

Re: Comments of American Municipal Power, Inc. on Proposed Rule: Clean Air Act 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. 88 Fed. Reg. 33240 (May 23, 2023)

Dear EPA Administrator Regan and Agency Staff:

In response to the above-referenced docket, American Municipal Power, Inc. ("AMP") hereby provides the following comments for the record. While AMP is supportive of the promulgation of a rule to reasonably regulate the emission of greenhouse gases ("GHG"), the "New Source Performance Standards for Greenhouse Gas Emissions from New, Modified, and Reconstructed Fossil Fuel-Fired Electric Generating Units ("EGUs"); Emission Guidelines for Greenhouse Gas Emissions from Existing Fossil Fuel-Fired Electric Generating Units; and Repeal of the Affordable Clean Energy Rule" ("Proposed Rule")[1] contains many legal and structural flaws, which are discussed further herein. Any rulemaking to regulate the emissions of GHG should be consistent with existing statutory authority while providing certainty and predictability to the regulated community while minimizing the impact on the reliability and affordability of electricity. Therefore, AMP requests that the Environmental Protection Agency ("EPA") reconsider the Proposed Rule.

[1] 88 Fed. Reg. 33240 (May 23, 2023).

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BACKGROUND ON AMP

AMP is the nonprofit wholesale power supplier and services provider for 132 members in the states of Indiana, Kentucky, Maryland, Michigan, Ohio, Pennsylvania, Virginia, West Virginia; as well as the Delaware Municipal Electric Corporation, a joint action agency with eight Delaware municipal members. AMP's members collectively serve approximately 650,000 residential, commercial, and industrial customers and have a system peak of more than 3,400 megawatts ("MW"). AMP's core mission is to be public power's leader in wholesale energy supply and value-added member services. AMP offers its member municipal electric systems the benefits of scale and expertise in providing and managing energy services. AMP serves as a joint action organization, representing 133 members with a broad spectrum of unique views and we recognize that some of our members may be filing separate comments.

On behalf of our membership, AMP's renewable and advanced power assets include a variety of base load, intermediate and distributed peaking generation using hydropower, wind, landfill gas, solar and fossil fuels, as well as a robust energy efficiency program. AMP has actively worked for more than a decade to diversify our power supply portfolio to significantly expand our renewable owned assets. AMP and our members operate and maintain multiple hydroelectric projects situated along the Ohio River at existing U.S. Army Corps of Engineers locks and dams. These facilities represent one of the largest deployments of clean, renewable run-of-the-river hydroelectric generation in the country. Our fossil fuel assets currently include a 368 MW ownership share of the 1,600 MW coal-fired Prairie State Generating Company located in Lively Grove, Illinois, ("Prairie State"), the 685 MW natural gas combined cycle AMP Fremont Energy Center in Fremont, Ohio ("AFEC") and multiple small natural gas and diesel peaking units. Most of AMP's members are in the PJM Interconnection, L.L.C. ("PJM") regional transmission organization ("RTO") footprint, while some members are located within the Midcontinent Independent System Operator, Inc. ("MISO") footprint.

Because of AMP's structure as a nonprofit wholesale power provider, we closely follow regulatory initiatives that have the potential to impact the costs and reliability of our members' energy and capacity supply. To that end, AMP's past public comments on the EPA's GHG rulemakings reflected expected impacts of the standards on AMP's and AMP's members' generating units, as well as on other units in the region, from which AMP members might acquire varying portions of their power supply through wholesale market purchases. As we have expressed in past comments, the multi-state nature of AMP's membership and power supply portfolio, plus the various types of electricity markets within which we operate, all point to the need for careful consideration of all options in addressing GHG emissions, and an acknowledgment that "one size does not fit all" when it comes to carbon standards.

In recognition of our unique position as both representing load and as the owner and operator of electric generating assets in Illinois, Kentucky, Michigan, Ohio, Pennsylvania, and West Virginia, AMP offers the following comments for consideration.

BACKGROUND

In 2009, the EPA found that GHGs are pollutants under the Clean Air Act ("CAA") and that GHG emissions endangered the public health and welfare.[2,3] Since then, EPA has sought an effective approach to GHG regulation that aligns with the policy goals of different presidential Administrations, fits within U.S. Supreme Court decisions and CAA statutory authorities, and is structured such that it can survive the legal challenges that come with any major regulatory action associated with climate change.

In *West Virginia v. EPA*, the U.S. Supreme Court struck down the EPA's "outside the fence" approach under the Clean Power Plan ("CPP"), which included a cap-and-trade system that would result in a shift of electricity production from coal-fired plants to other sources with lower GHG emissions. The Court concluded that such action exceeded EPA's power under Section 111(d) to establish the "best system of emissions reductions" that has been "adequately demonstrated" and that such generation shifting from coal to other sources constituted a "major question" of great economic significance.[4] As such, a clear statutory authorization from Congress was required, and was missing in the case of the CPP. Therefore, the language of Section 111(d) did not support EPA's conclusion that it could use a cap-and-trade or other system extending beyond the confines of a particular generator to address GHG pollutants.

To address the Court's holding in *West Virginia v. EPA*, on May 23, 2023, EPA provided its latest effort to regulate GHG emissions with the Proposed Rule. The Proposed Rule applies varying determinations of the Best System of Emissions Reduction ("BSER") and compliance timelines depending on the type and status of an EGU.

With respect to the remaining combustion turbines, EPA has indicated that it intends to undertake a separate rulemaking as expeditiously as practicable to establish emission guidelines for limiting carbon dioxide ("CO_2") emissions from combustion turbines not covered by this rule.

While EPA asserts that the Proposed Rule complies with the CAA framework by implementing "inside the fence line" requirements, the Proposed Rule suffers from additional flaws, including: 1) Carbon Capture and Storage ("CCS") and low-GHG hydrogen have not been "adequately demonstrated" through development and practical implementation to constitute BSER and will be exorbitantly costly; and 2) the Proposed Rule requirements cannot be achieved in the timeframe included without impacting the reliability of the electric grid. As a result of mandating the use of technology that is yet to be adequately demonstrated, achievable, or cost-effective within an unreasonable timeframe, utilities will be forced to either prematurely retire units or severely limit their use to comply with these rules.

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[2] 74 Fed. Reg. 66495 (December 15, 2009).

[3] *Massachusetts v. EPA*, 549 U.S. 497 (2007).

[4] 142 S. Ct. 2587 (2022).

AMP supports efforts to mitigate the impacts of climate change. However, it is essential that any regulatory structure be reasonable, achievable, and consider input from all potential stakeholders. This is particularly true of the Proposed Rule as it will substantially affect multiple sectors of the U.S. economy beyond the electric industry that it targets, well into the future. AMP has significant concerns about the Proposed Rule regarding the anticipated impact on grid reliability and affordability. The Proposed Rule depends on technologies, such as low-GHG hydrogen and CCS, which are unproven at the scope and scale necessary to comply with this proposal. The aggressive schedule set forth in the Proposed Rule provides little time for these technologies to mature and may leave fossil-based plant operators with no viable alternative to closure. As a result, AMP is concerned that the rules will contribute to a national and regional loss of necessary dispatchable baseload generation potentially undermining the reliability and resiliency of the bulk electric system and having a profoundly negative impact on AMP's, our members' and public power's ability to provide reliable and affordable electricity to our residents and businesses. This concern is compounded by today's supply chain constraints and permitting, interconnection and construction timeframes. As such, AMP respectfully requests EPA reconsider the Proposed Rule to allow for a more thorough discussion and comprehensive analysis of impacts. AMP provides its comments below for EPA's consideration on the final rule.

AMP COMMENTS

I. Proposed Rule Applicability

a. AMP supports EPA exemptions for small or infrequently operated units.

In the Proposed Rule, EPA solicits comment on how it should approach establishing emissions guidelines for existing fossil fuel-fired units that are not covered by the Proposed Rule, specifically smaller, less frequently operated units.[5] AMP supports the applicability thresholds that exclude small EGUs from this Proposed Rule. The Proposed Rule's current exemption for smaller, less utilized steam generating units and combustion turbines is essential to ensuring reliability during the transition to more intermittent EGUs. AMP supports the exemption of small, infrequently operated coal units in any final rule for the reasons outlined below.

Proposed section 40 CFR 60.5845b identifies which EGUs must be addressed in a state plan for existing sources. Section 40 CFR 60.5845b(b) defines an "affected EGU" as a steam generating unit or natural gas-fired stationary combustion turbine that meets the following conditions:

(1) Serves a generator capable of selling greater than 25 MW to a utility distribution system; and

[5] 88 Fed. Reg. 33240, 33242 (May 23, 2023).

(2) Has a base load rating (i.e., design heat input capacity) greater than 260 GJ/hr (250 MMBtu/hr) heat input of fossil fuel (either alone or in combination with any other fuel).

The above applicability criteria are further qualified by the exemptions contained in section 40 CFR 60.5850b for existing units. Even if not satisfying both above conditions, an EGU meeting these exemptions is not an "affected EGU", and thus not subject to the rule. The section 40 CFR 60.5850b exemptions include, but are not limited to:

(1) Natural gas fired stationary combustion turbines with an electric generating capacity equal to or less than 300MW or with an electric generating capacity of more than 300 MW and that operate at an annual capacity factor equal to or less than 50 percent;

(2) Steam generating units subject to a federally enforceable permit limiting net-electric sales to one-third or less of their potential electric output or 219,000 MWh or less on an annual basis and annual net-electric sales have never exceeded one-third or less of their potential electric output of 219,000 MWh;

(3) CHP units that are subject to federally enforceable permit limiting annual net electric sales to no more than either 219,000 MWh or the product of the design efficiency and the potential electric output, whichever is greater;

(4) Units that serve a generator along with other steam generating unit(s), where the effective generation capacity (determined based on prorated output of the base load rating of each steam generating unit) is 25 MW or less.

The applicability criteria for new, modified, or reconstructed EGUs in sections 40 CFR 60.5509 and 40 CFR 60.5509a mirror that which must be included in state plans for existing units. Namely, to be subject to the rule a unit must:

(1) Serve as a generator capable of selling greater than 25MW to a utility distribution system; <u>*and*</u>

(2) Have a base load rating (i.e., design heat input capacity) greater than 260 GJ/hr (250 MMBtu/hr) heat input of fossil fuel (either alone or in combination with any other fuel).

Included in sections 40 CFR 60.5509/60.5509a are exemptions focused on smaller units that include, but are not limited to, the following:

(1) A steam generating unit or IGCC whose annual net electric sales have never exceeded one-third of its potential electric output or 219,000 megawatt-hour (MWh), whichever is greater, and is currently subject to a

federally enforceable permit condition limiting annual net-electric sales to no more than one-third of its potential electric output or 219,000 MWh, whichever is greater.

(2) A combined heat and power unit that is subject to a federally enforceable permit condition limiting annual net-electric sales to no more than either 219,000 MWh or the product of the design efficiency and the potential electric output, whichever is greater.

(3) An EGU that serves a generator along with other steam generating unit(s), IGCC, or stationary combustion turbine(s) where the effective generation capacity (determined based on a prorated output of the base load rating of each steam generating unit, IGCC, or stationary combustion turbine) is 25 MW or less.

AMP supports the Proposed Rule's applicability thresholds such that small and/or infrequently operated fossil fuel-fired steam generating units and gas-fired turbines are not impacted by the requirements set forth in the Proposed Rule. While thermal EGUs (coal and natural gas) are dispatchable energy resources that can be called upon when needed to provide energy, non-thermal resources such as solar and wind are non-dispatchable resources, meaning they cannot be called upon to produce energy on demand. Thus, as the bulk power system transitions towards an increased reliance on intermittent/nonthermal renewable EGUs, these limited-use units are essential to balance the supply and demand needs on the electric grid in real time. In recognition of this critical function, EPA should not establish emissions guidelines for existing fossil fuel-fired resources that are not covered by the Proposed Rule.

b. The Proposed Rule should not pro-rate steam turbine generating capacity to calculate applicability to combustion turbines.

The Proposed Rule states that combustion turbines of more than 300 MW and more than 50% capacity factor would be subject to the proposed standard. The Proposed Rule includes a definition of stationary combustion turbine.[6] Nowhere within the Proposed Rule (within the definition of turbine or otherwise) is there a discussion of the need to pro-rate steam units across generating capacity to identify applicable combustion turbines. Thus, AMP and other generators relied on the plain language of the Proposed Rule to determine potential applicability of its units against the Proposed Rule requirements.

[6] Pursuant to 40 CFR 60.5580 (Proposed Rule Language, Subpart TTTT – Standards of Performance for Greenhouse Gas Emissions for Electric Units), a stationary combustion turbine is defined as "including, but not limited to, the turbine engine, the fuel, air, lubrication and exhaust gas systems, control systems (except emissions control equipment), heat recovery system, fuel compressor, heater, and/or pump, post combustion emission control technology, and any ancillary components and sub-components comprising any simple cycle stationary combustion turbine, any combined cycle combustion turbine, and any combined heat and power combustion turbine based system plus any integrated equipment that provides electricity or useful thermal output to the combustion turbine engine, heat recovery system, or auxiliary equipment…"

However, on June 12, 2023, EPA published guidance to address emission guideline applicability for existing stationary combustion turbines.[7] The guidance states that the generating capacity of the steam turbine would be pro-rated across the number of gas turbines at a natural gas combined cycle ("NGCC") plant. The guidance was based on definitions and calculations that appear nowhere in the Proposed Rule's applicability section. EPA appears to be establishing an expanded applicability interpretation through supplemental guidance without recognition and associated updates to Proposed Rule support documents. This regulation through guidance, without accompanying supporting information or adequate time to review and comment, should not be used in a rulemaking of this magnitude.

The AFEC NGCC plant, equipped with two natural gas-fired combustion turbines rated at 190.4 MW each and an HRSG steam turbine rated at 358.7 MW, was initially viewed as exempt from the proposed standard. However, that expectation changed upon EPA's publication of the guidance which stated that the generating capacity of the steam turbine is pro-rated across the number of gas turbines at an NGCC plant. Based on that guidance, AFEC would now be subject to the Proposed Rule despite not having any combustion turbines at the facility rated over 300 MW because the 358.7 MW of steam capacity would be divided and allocated to the combustion turbines, resulting in each having 369.75 MW of capacity.

The EPA's guidance also contradicts the Regulatory Impact Analysis ("RIA"). According to the RIA, EPA performed its evaluation on NGCC plants "with average unit size greater than 300 MW that are projected to operate at greater than 50 percent capacity factor in the 2035 run year."[8] The RIA does not reference the steam turbine allocation and would not have included AFEC as subject to the Proposed Rule using the RIA criteria. Moreover, the RIA focused on baseload plants defined as operating at a capacity factor of greater than 80%. Plants operating at greater than 50% capacity factors may not be operating in a baseload capacity. For example, as noted above, AFEC NGCC EGU operates as an intermediate load facility with frequent ramping up/down and load-following capabilities. EPA also fails to recognize that larger turbines tend to be more efficient, requiring less fuel per MWh output than smaller turbines. Consequently, AFEC is essentially being penalized by EPA for more efficient operation and lower GHG emission intensity. AMP respectfully requests EPA to revise the proposed capacity factor threshold for existing NGCC plants to accurately reflect baseload operation in accordance with EPA's own assessment, defined as operating at greater than 80% capacity factor.

On July 7, 2023, EPA released updated Integrated Proposal Modeling ("IPM") that states: "The updated modeling summarized in this document continues to be based on the applicability criteria for affected units that the EPA included in the proposed rulemaking."[9] This statement is incorrect. The applicability criteria for affected units in the

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[7] Applicability of Emission Guidelines to Existing Stationary Combustion Turbines: FAQs, memo to the Docket. Docket ID No. EPA-HQ-OAR-2023-0072, June 12, 2023.

[8] RIA, Sec. 8.2.

[9] Integrated Proposal Modeling and Updated Baseline Analysis. EPA. July 7, 2023, p. 5.

Proposed Rule for combustion turbines was a generating capacity of 300 MW or more that operates at an annual capacity factor greater than 50%.[10] Further, EPA fails to recognize it has provided three different “applicability criteria” for NGCC plants under the Proposed Rule thus far. It is difficult to understand how EPA can model and analyze the operational and financial impacts of the Proposed Rule on three very different populations of NGCC plants without having to make changes to other parts of the Proposal.

Adding to this confusing web of competing applicability criteria and modeling assumptions, EPA included as part of the July 7 IPM that: “As noted in the proposed rulemaking, EPA is also considering certain variations in those applicability requirements, including, for existing NGCC units and natural gas combustion turbines (“NGCT”), variations in the proposed threshold of 300 MW. In addition, while the proposed rulemaking applied that threshold on a unit-level basis, and all of the modeling performed to date does the same, comments from stakeholders to date have led the EPA to also consider applying the threshold on a plant-level basis. EPA is considering the appropriate MW threshold for such a plant-level approach and whether such an approach should also include a unit-level MW threshold.”[11] How EPA applies this rule has profound implications on generation owners, stakeholders, and the bulk power system. Accordingly, these questions are better suited for a supplemental rulemaking proposal, not a supporting document that was released with little fanfare for the regulated community to happen upon. Any final rule must clearly identify which existing combustion turbines are regulated thereunder. The different applicability criteria presented in the Proposed Rule, RIA, the June 12 guidance, and now the July 7 modeling update renders the Proposed Rule applicability incomprehensible, and it is not reasonable to expect stakeholders to comment on a moving target of applicability.

This rulemaking needs to be clear and concise with respect to which units are to be regulated. EPA should define applicable units as those individual turbines (without steam generator(s), consistent with KKKK definition[12]) greater than 300 MW, and with greater than 80% capacity factor. Without such clarity, the Proposed Rule is unreasonably broad and incompatible with efficient, low GHG emission operation.

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[10] Proposed Emission Guidelines, 40 CFR 60.5850b(a).

[11] Integrated Proposal Modeling and Updated Baseline Analysis. EPA. July 7, 2023, p. 5.

[12] 40 CFR 60.4420 (Subpart KKKK) defines a combustion turbine as “all equipment, including but not limited to the turbine, the fuel, air, lubrication and exhaust gas systems, control systems (except emissions control equipment), heat recovery system, and any ancillary components and sub-components comprising any simple cycle stationary combustion turbine, any regenerative/recuperative cycle stationary combustion turbine, any combined cycle combustion turbine, and any combined heat and power combustion turbine based system...”

II. EPA should withdraw and re-propose the Proposed Rule.

Notwithstanding the fact that AMP supports the exemptions from the Proposed Rule discussed above, for the reasons discussed herein, AMP has serious concerns with the Proposed Rule, including that it: 1) relies on questionable data and assumptions with respect to the technologies used as the BSER; 2) makes unrealistic assumptions about the availability and timing of the infrastructure necessary to support the assumed development and use of CCS and green hydrogen; 3) conflicts significantly with reliability concerns of other federal and state agencies responsible for electric reliability; 4) would substantially increase the cost of electricity to consumers; and 5) does not provide states with sufficient time or flexibility to develop, implement or modify when appropriate their plans for implementation. For all of these reasons and others discussed in these comments, AMP urges EPA to withdraw and re-propose the rule.

III. EPA's BSER determinations do not comply with CAA Section 111 requirements.

A key condition for a system of emissions reduction to form the basis of an achievable emissions limitation under CAA Section 111(a)(1) is that the EPA must determine that the system is "adequately demonstrated." To be adequately demonstrated, a system must be "one which has been shown to be reasonably reliable, reasonably efficient, and which can reasonably be expected to serve the interests of pollution control without becoming exorbitantly costly in an economic or environmental way."[13] While the D.C. Circuit allowed for some degree of projection, any projection "…*is subject to the restraints of reasonableness and cannot be based on 'crystal ball' inquiry*."[14] Nonetheless, the Proposed Rule relies upon the use of two technologies that are not in actual or routine use and that would be exorbitantly costly. Accordingly, the EPA should reconsider the Proposed Rule to allow more thorough discussion and consideration.

a. CCS does not constitute BSER.

The Proposed Rule requires the use of CCS with 90% capture of CO_2 as BSER for coal-fired steam EGUs that will operate in the long-term (i.e., after December 31, 2039). However, CCS has never been successfully deployed domestically on a scale necessary to conclude it is an "adequately demonstrated" technology.

There are five general industrial categories in which facilities either are employing or developing projects to capture and inject CO_2: chemical production, hydrogen production, fertilizer production, natural gas processing, and power generation. Of these five categories, four produce or can produce CO_2 in a highly concentrated exhaust stream. One such chemical processing example is ethanol production, where the exhaust from fermentation tanks typically consists of over 99% CO_2 and some trace organic

[13] *Essex Chem. Corp. v. Ruckelshaus*, 486 F.2d 427, 433 (D.C. Cir. 1973), cert. denied 416 U.S. 969 (1974).

[14] *Id.*

pollutants. Power generation from the combustion of fossil fuels produces a dilute stream of CO_2 (13-15% for coal power plants and 3-4% for natural gas plants),[15] which is more technically and economically demanding to concentrate and capture. AMP notes that in EPA's Technical Support Document for CCS, only one domestic site is referenced (Bellingham Energy Center) which ceased operation in 2005 and captured 85 to 95% of the CO_2 in the slipstream, not the full exhaust, of one boiler for use in the food industry and references several "announced" facilities and facilities "in development."[16] However, only one such facility in the U.S. has generated electricity on a commercial scale while capturing CO_2—the Petra Nova facility in Texas.[17] Similar to the Boundary Dam project in Canada, Petra Nova was designed to capture the equivalent of a 240 MW exhaust stream from the 650 MW W.A. Parish Unit 8.[18] Moreover, the Petra Nova project, which began operation in 2017, suspended CCS operation in 2020, and announced in early 2021 plans to indefinitely shut down the CCS equipment's power source.[19] The owner of the plant (now JX Nippon Oil & Gas Exploration) has announced plans to restart the project but has not done so as of this writing. There are certainly projects under development other than the Petra Nova project (which operated from 2017-2020), but no large U.S. commercial electricity generating plant has been successfully equipped with CCS equipment. Given the above, AMP cannot reconcile EPA's conclusion that the "adequately demonstrated" standard has been met.

In addition to the fact that CCS has never been successfully deployed domestically on a scale necessary to conclude it is an "adequately demonstrated" technology, all fossil fuel-fired power plants do not operate in a uniform set of environments. Specifically, state and federal permitting requirements will present significant financial and timing restraints and hurdles, particularly for facilities that will need a pipeline to implement required CCS technologies. While the proposed section 40 CFR 60.5740(a)(4)(v) recognizes there will be permitting obligations for sites where on-site CCS is impracticable and thus will require pipeline transport, there is no indication that these permits will be issued or obtained in a timely manner. Planning for new pipeline capacity must begin well in advance of an actual construction and operational goal. Pipeline companies must determine possible routes, obtain rights-of-way to operate and maintain the pipeline, design and engineer the pipeline, address state and federal environmental and other regulations such as the federal Endangered Species Act, and obtain all necessary regulatory approvals before actual construction can commence. In fact, a review of timelines for new pipelines

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[15] 9.2 Carbon Dioxide Capture Approaches. National Energy Technology Laboratory. 9.2. Carbon Dioxide Capture Approaches | netl.doe.gov. Last viewed Jul. 18, 2023.

[16] Greenhouse Gas Mitigation Measures; Carbon Capture and Storage for Combustion Turbines: Technical Support Document. Docket ID No. EPA-HQ-OAR-2023-0072, May 23, 2023.

[17] "Carbon capture and Sequestration (CCS) in the United States", Congressional Research Service, October 5, 2022.

[18] "Capturing Carbon and Seizing Innovation: Petra Nova Is POWER's Plant of the Year" Power Magazine (online). Aug. 1, 2017. https://www.powermag.com/capturing-carbon-and-seizing-innovation-petra-nova-is-powers-plant-of-the-year/. Last viewed Jul. 18, 2023.

[19] "Power Plant Linked to Idled U.S. Carbon Capture Project Will Shut Indefinitely", Reuters, January 29, 2021.

demonstrates that unless planning commenced today, it is unlikely that siting of a pipeline could be achieved to meet the Proposed Rule's deadlines.[20] This regulatory reality is the same for permitting underground injection, where facilities can inject CO_2 on-site. The Proposed Rule fails to include contingencies when pipeline and/or injection permitting is delayed or denied. In addition to permitting challenges, CCS, CO_2 pipelines and injection wells face a number of challenges that could slow or prevent deployment including local property rights and rights-of-way, siting and construction, public acceptance hurdles, property rights for subsurface CO_2 storage, and long-term liabilities and stewardship of CO_2.

Moreover, for a technology to be BSER it must be able to be implemented throughout the country because such a standard is the minimum performance standard that all sources must achieve. Therefore, CCS is inappropriate due to its geographic and site limitations. For example, not all geographic locations will be conducive to storage due to geology or size constraints or have the significant water source available that will be required for such technology.

In addition to not being adequately demonstrated, deployment of CCS technology is a significant multi-phase project that necessitates substantial resources, planning and time. Absent necessary funding and partners, the initial development and planning phases, combined with development costs are significant. EPA cites and relies extensively on the National Energy Technology Laboratory ("NETL") "Quality Guidelines for Energy System Studies: Carbon Dioxide Transport and Sequestration Costs in NETL Studies" when discussing costs to implement such technology.[21] However, the study did not address issues unique to CSS implementation and transport at a variety of EGUs and consequently, universal, generic cost estimates are unreliable and inaccurate when applied in consideration of EGUs that require the construction of a pipeline to an injection or use site, given the variability of pipeline costs. This would be true even if there was more established technology as it relies on a single example rather than many data points from real-world domestic implementation.

Even ignoring the cost and timing issues related to CCS pipeline siting and infrastructure, the cost of retrofitting CCS equipment onto an existing coal-fired power plant is substantial, particularly absent federal and state funding support and partnerships. Prairie State has explored installation of CCS on one unit. As noted in the introduction, AMP has an ownership stake in the coal-fired Prairie State EGU, a 1,600 MW power plant in Lively Grove, Illinois. Prairie State Generating Station started construction in 2007 and came online in late 2012. It is a modern supercritical pulverized coal plant with state-of-the-art control systems for conventional pollutants. The plant's cost was approximately $4.93 billion, with AMP financing its portion of the construction

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[20] See: GAO-18-693T, ENERGY INFRASTRUCTURE PERMITTING: Factors Affecting Timeliness and Efficiency and GAO-13-221, Pipeline Permitting: Interstate and Intrastate Natural Gas Permitting Processes Include Multiple Steps, and Time Frames Vary.

[21] Quality Guidelines for Energy Studies, Carbon Dioxide Transport and Storage Costs in NETL Studies. NETL. August 2019. Quality Guidelines for Energy System Studies: CO2T&S (doe.gov). Last viewed August 1, 2023.

costs. AMP's subscribing municipal members are required to pay their share of the costs of construction and operation of the plant. This includes any additional control equipment required by EPA.

The proposed CO_2 performance standards are not based on a CCS control technology that is adequately demonstrated. While the technology has been demonstrated as feasible at a few CCS pilot projects, they do not prove that CCS is adequately demonstrated for broad commercial deployment as required under section 111 of the CAA. The large federal subsidies that are needed to offset the high costs of permitting approvals, feasibly and cost-effectively capturing CO_2 at the rate proposed in this rule, transporting and subsequently sequestering the CO_2 in appropriate geologic storage, among other operation and other challenges, indicate that CCS as a BSER has not yet been "adequately demonstrated."

The Proposed Rule also includes CCS as a cost-effective control measure for baseload NGCC plants. EPA's Technical Service Document "Greenhouse Gas Mitigation Measures; Carbon Capture and Storage for Combustion Turbines" assumes CCS is operated at a steady state where the exhaust stream composition, temperature, flow rate, and other operating parameters are stable, which allows the CCS system to work effectively.[22] The NETL documents on retrofitting NGCC plants with CCS indicate that such a system may be cost-effective (inclusive of incentives) when operated at a capacity factor of 85%.

Even if it is true that CCS can be cost-effective for baseload NGCC plants, CCS for NGCC plants that are not baseload has not been demonstrated to be a cost-effective control system. Many NGCC plants operate as intermediate facilities and have the capability to ramp up and down to efficiently follow load – precisely the sort of plant needed to support the increasing penetration of renewable generation. The parasitic load of a CCS system will increase operating costs of NGCC plants, resulting in either the units running at high capacity factors to be efficient or being dispatched less, as RTO markets dispatch based on cost. Running less impacts cost recovery of the investment for NGCC plant owners but running at higher capacity could result in the curtailment of renewable resources. Additional modeling is needed to better understand the financial and market impacts of CCS as a compliance option on NGCC plants, particularly given that existing NGCC plants were not adequately modeled in the RIA issued with the Proposed Rule. [23]

Even the NETL study cited by EPA that examined the feasibility and cost of a CCS retrofit on NGCC EGUs concluded that such controls were barely cost effective at an 85% capacity factor and only when considering available incentives for carbon capture. CCS will be even less cost-effective below that level or if the assumed subsidies are unavailable. Nonetheless, EPA concludes that "model plants, those that were projected to operate at higher capacity factors in 2035, 2040 and 2045 were assumed to install CCS

[22] Greenhouse Gas Mitigation Measures; Carbon Capture and Storage for Combustion Turbines: Technical Support Document. Docket ID No. EPA-HQ-OAR-2023-0072, May 23, 2023.

[23] RIA, Sec. 8.3.3.

rather than finding an alternative compliance pathway given plant economics."[24] However, EPA has not established justifiable analysis that CCS is adequately demonstrated for NGCC plants with capacity factors below 85%.

As discussed in greater detail herein, because EPA has made Inflation Reduction Act ("IRA") funding a linchpin of its BSER being cost-effective, any materially adverse impacts on IRA funding will result in the failure of EPA's BSER determinations. For example, EPA asserts that by 2030-2040, funding from programs established under the IRA will decrease costs and enable the construction of needed infrastructure such as low-GHG hydrogen production hubs, CCS projects, pipelines to transport captured CO2 and hydrogen and additional transmission resources.[25] However, the recent debt ceiling dispute is a likely harbinger of future attacks on IRA programs. As such, availability of IRA funding is not a long-term guarantee.

Failing to consider the practical aspects of deployment of CCS at existing power plants simply invites additional litigation that has been the hallmark of efforts to regulate GHG emissions over the years, as well as undermines the foundation of EPA's BSER approach. Given the above considerations, CCS is not adequately demonstrated and so cannot constitute BSER.

b. Hydrogen co-firing does not constitute BSER under Section 111(a)(1).

The Proposed Rule requires that natural gas-fired combustion turbines with 300 MW generation or greater that operated at a capacity factor greater than 50% must begin co-firing low-GHG hydrogen starting at 30% in 2032 and increasing to 96% by 2038 or, in the alternative, install full CCS with 90% capture by 2035. Like CCS, low GHG hydrogen co-firing technology has not been adequately demonstrated.

While a number of turbine manufacturers have certified existing natural gas combustion turbines to operate on 30% hydrogen blended with natural gas (on a volume basis) with no or minor changes, AMP is unaware of any that have demonstrated the ability to meet the 96% hydrogen mark. It is also not clear that existing turbines could fire that volume of hydrogen without having to make changes that would constitute a "modification" or "major modification" necessitating additional permitting. Additionally, this "certification" of existing turbines doesn't necessarily apply to the "balance of plant" systems—just to the turbines.

For low-GHG hydrogen there are power and water constraints that will restrict adoption of this compliance option if infrastructure to transport hydrogen is lacking. Existing generators simply cannot self-supply green hydrogen without bringing in additional power, and there isn't sufficient excess power from solar to ensure the final

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[24] *Id.*

[25] H.R. 5376 (as amended by the Senate); Inflation Reduction Act of 2022.

product is "green."[26] The quantities of hydrogen needed to operate a natural gas combined cycle plant are significant, as is the quantity of water needed to produce that hydrogen.

Gas Turbine	Output† MW	Heat Input† GJ/hour (MMBTU/hour)	100% H_2 Flow Rate m^3/hour (ft^3/hour)	Water Required to Generate H_2 m^3/hour (gallons/hour)	Electrolysis Power Required†† GWh
GE-10	11.2	129 (122)	~11,700 (~446,000)	~10 (~3,700)	~500
TM2500	34.3	350 (332)	~31,800 (~1,210,800)	~27 (~7,300)	~1,500
6B.03	44.0	473 (448)	~ 43,000 (~1,635,900)	~37 (~9,900)	~2,000
6F.03	87	857 (813)	~78,000 (2,970,000)	~68 (~17,950)	~3,600
7F.05	243	2,197 (2,083)	~200,000 (~7,600,000)	~174 (~46,000)	~9,400
9F.04	288	2,677 (2,537)	~243,500 (~9,266,900)	~212 (~56,000)	~11,400
9HA.02	557	4,560 (4,322)	~415,000 (~15,786,400)	~361 (~95,500)	~19,500

† ISO conditions operating on natural gas
†† Power required for electrolysis to supply H_2 flow for gas turbine to operate on 100% H_2 for 8000 hours

From GEA33861 – Power to Gas – Hydrogen for Power Generation, Table 3[27]

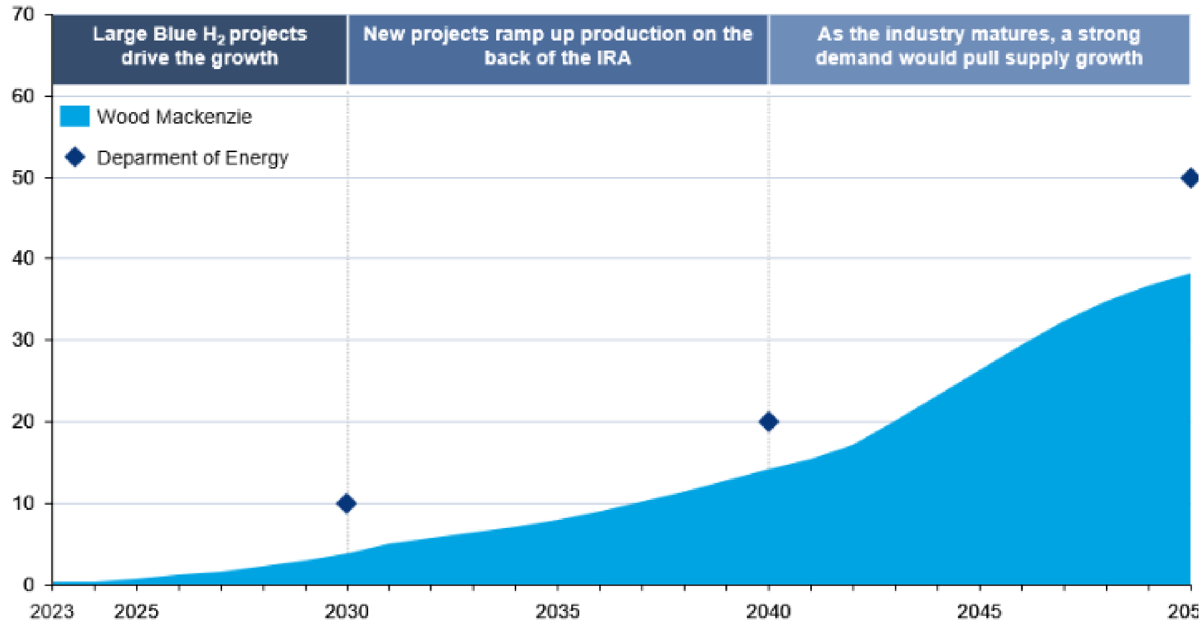
As can be seen in the table reproduced above, it is not feasible for a turbine to operate as a base load unit and power the hydrogen electrolyzers needed to produce enough fuel to operate. For example, the 9HA.02 model gas turbine has a rated capacity of 557 MW. Over the course of 8,000 hours of operation, it would generate 4,456 GWh of power (557 MW * 8,000 hours = 4,456,000 MWh or 4,456 GWh) but it would take more than four times that amount of power just to produce the hydrogen needed to fuel that turbine. In addition, nearly 100,000 gallons per hour of water would be needed to supply the hydrogen electrolyzers. This is equivalent to approximately four Olympic-sized swimming pools per day.

Setting aside the significant technical issues of using hydrogen in existing turbines, low-GHG hydrogen is not available in large enough quantities to meet the Proposed Rule requirements and availability in the future remains a question. Despite the efforts in Congress and the Department of Energy, the hydrogen production targets outlined in the recently published "National Clean Hydrogen Strategy and Roadmap" will fall well short of projections.[28]

[26] Electrolyzers: The tools to turn hydrogen green. July 3, 2023. Craig Bettenhausen. C&EN 2023 101(21), pp 25-30.

[27] GEA33861 Power to Gas – Hydrogen for Power Generation *Fuel Flexible Gas Turbines as Enablers for a Low or Reduced Carbon Energy Ecosystem*. Dr. Jeffery Goldmeer. GE Power. 2019.

[28] U.S. National Clean Hydrogen Strategy and Roadmap. U.S. National Clean Hydrogen Strategy and Roadmap (energy.gov). Last viewed August 1, 2023.



Source: Wood Mackenzie

As noted by Wood Mackenzie Ltd., several factors make meeting these production targets unlikely, such as "renewable power costs, electrolyzer load factor, and a slower decline in capital expenditures for electrolytic hydrogen (which is projected to be around US $1,600/kW in 2030)."[29] At the 2030 predicted future levels (4-5 million metric tons) outlined by Wood Mackenzie Ltd., the supply of low GHG hydrogen may be insufficient to meet power sector demands, assuming there is at least some demand from other sectors of the economy.[30] Even if supply were adequate, EPA ignores the needed pipeline infrastructure to transport this fuel to existing turbines. While there has been some evaluation of the suitability of current natural gas pipeline infrastructure for blended service with 30% by volume hydrogen, it is not at all certain that utilizing existing pipeline infrastructure is entirely feasible. New pipeline transportation infrastructure would be required by 2038 in any case to transport 96% green hydrogen. Current permitting timelines argue against these pipelines being constructed in time.

As with CCS, EPA fails to support its conclusion that hydrogen co-firing has been adequately demonstrated and is cost-effective. The lack of any natural gas combustion turbines operating on 96% hydrogen blended with natural gas (on a volume basis) with no or minor changes undermines EPA's conclusion that hydrogen co-firing technology has been adequately demonstrated. Additionally, with high demand for low GHG hydrogen under this Proposed Rule coupled with low availability due to production and

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[29] "U.S. and Japan will struggle to hit ambitious hydrogen targets." Windfair (online). June 30, 2023. U.S. and Japan will struggle to hit ambitious hydrogen targets | windfair. Last viewed Jul. 26, 2023.

[30] *Id.*

supply constraints, limited supply would result in extremely high fuel costs. Accordingly, hydrogen co-firing cannot constitute BSER.

IV. The Proposed Rule raises concerns about reliability.

Electricity is an essential component of our lives and our economy, and decarbonization goals must be balanced with the need for affordable and reliable power for our homes and businesses. AMP has serious concerns that the requirements of the Proposed Rule will impact the ability of AMP's members to provide reliable and cost-effective electricity to customers.

Section 215 of the Federal Power Act ("FPA") authorizes the Federal Energy Regulatory Commission ("FERC") to approve and enforce reliability standards developed by the North American Electric Reliability Corporation ("NERC")[31] and various regional reliability entities.[32] The Proposed Rule acknowledges that reliability is an issue of concern but ultimately rests on a conclusion that it provides sufficient flexibility to avoid reliability concerns.[33] There is every indication, however, that the premature retirement of EGUs that will result from the Proposed Rule will lead to conflicts between EPA's policies and FERC's reliability standards. Moreover, by disregarding the FERC-approved reliability standards and by making its own reliability related determinations, EPA contravenes section 215 of the FPA by supplanting FERC as the ultimate authority over the reliability of the Bulk Power System ("BPS"). Further, under FPA section 202(c), when an emergency exists by reason of a sudden increase in the demand for or shortage of electric energy, the Secretary of Energy may require by order temporary connections of facilities and generation to address the emergency. While the FPA section 202(c) order has proven to be effective at addressing acute resource adequacy emergencies, implementation of the Proposed Rule could result in unpredictable baseload generation retirements, and in turn result in the inability of the grid to meet energy demands. Notwithstanding EPA's exemption of small, less frequently used EGUs for the time being, AMP is concerned that implementation of the Proposed Rule has a high likelihood of resulting in grid reliability issues, and that EPA has failed to factor this serious consequence into the rulemaking and timelines.

As noted above, the Proposed Rule rests on a finding that it will not significantly impact electric reliability. That finding, however, contravenes reports issued by the

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[31] NERC's area of responsibility spans the continental United States, Canada, and the northern portion of Baja California, Mexico. NERC is the Electric Reliability Organization (ERO) for North America, subject to oversight by the Federal Energy Regulatory Commission and governmental authorities in Canada. NERC's jurisdiction includes users, owners, and operators of the bulk power system, which serves nearly 400 million people. NERC (online) Last viewed August 1, 2023.

[32] 16 U.S.C. § 8240.

[33] 88 Fed. Reg. 33246 (May 23, 2023). "Finally, the EPA has carefully considered the importance of maintaining resource adequacy and grid reliability in developing these proposals and is confident that these proposed NSPS and emission guidelines-with the extensive lead time and compliance flexibilities they provide-can be successfully implemented in a manner that preserves the ability of the power companies and grid operators to maintain the reliability of the nation's electric power system."

agencies with statutory responsibility for establishing reliability standards. EPA's failure to defer to FERC, NERC, and the RTOs concerning issues that fall squarely within their respective expertise is arbitrary and capricious.[34]

Even prior to the Proposed Rule, agencies with regulatory authority over electric reliability and markets have published reports relating to the energy transition and have highlighted reliability concerns resulting from the retirement of thermal, baseload capacity (primarily coal- and natural gas-fired generators) without corresponding additions of new generating resources.[35] NERC issues periodic assessments of the BPS and, in December 2022, released a Long-Term Reliability Assessment that evaluates the long-term reliability of the North American BPS while identifying trends, emerging issues, and potential risks during the upcoming 10-year assessment period (2023-2032).[36] In the report, NERC concludes that, while most areas are projected to have adequate electricity supply resources to meet demand forecasts associated with normal weather, there are large areas of North America that either do not meet resource adequacy criteria (in red below) or may have insufficient availability of resources during extreme and prolonged weather events (in yellow below).[37] The report highlights trends that affect long-term electric grid reliability, including: 1) an increase in peak demand and energy resulting from energy transition programs; 2) insufficient transmission for large power transfers; and 3) emerging electrification challenges.[38]

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[34] *See*, e.g., *Motor Vehicle Mfrs. Ass'n v. State Farm Mut. Auto. Ins. Co.*, 463 U.S. 29, 43 (1983) (agency action will be upheld only if it "articulates a satisfactory explanation for its action including a 'rational connection between the facts found and the choice made'") (quoting Burlington Truck Lines, Inc. v. United States, 371 U.S. 156, 168 (1962)).

[35] For example, 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 electric 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.

[36] 2022 Long-Term Reliability Assessment. NERC. December 2022. 2022_LTRA (nerc.com) Last viewed August 1, 2023.

[37] *Id.* at p. 2, 6.

[38] *Id.* at p. 7.

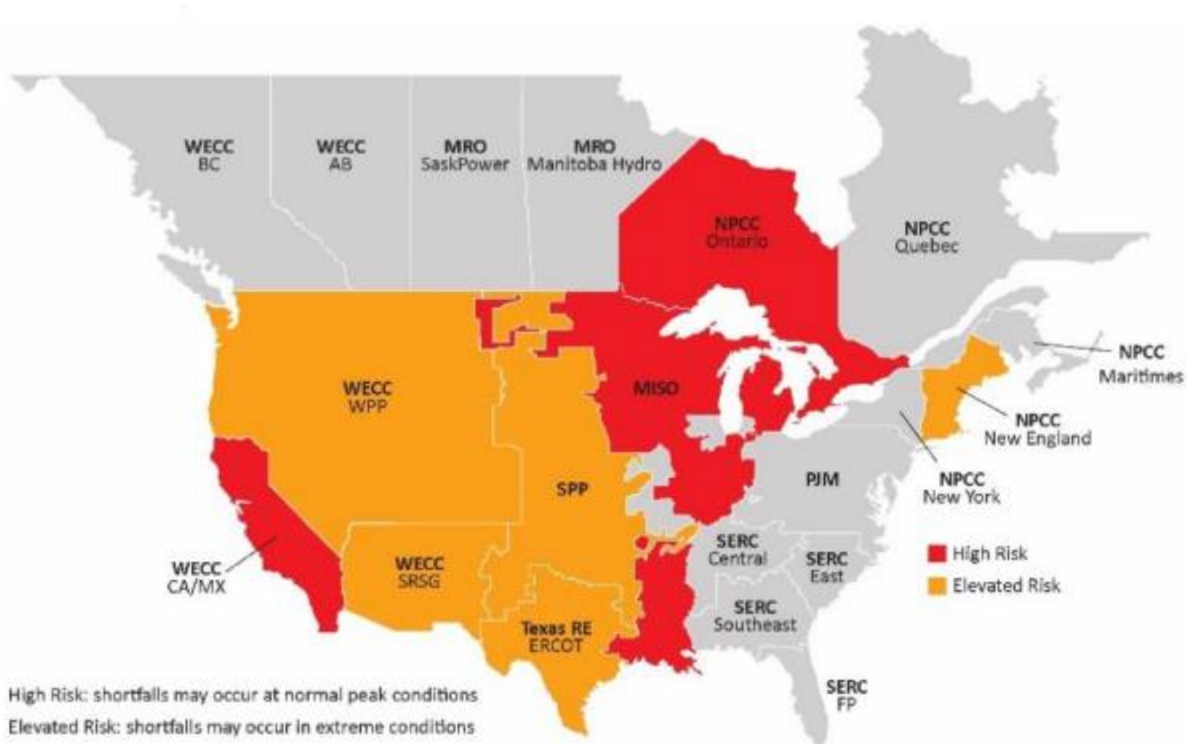

Figure 1: Risk Area Summary 2023–2027

The NERC report notes that the energy and capacity risks identified in the assessment underscore the need for reliability to be a top priority for the resource and system planning community of stakeholders. "Planning and operating the grid must increasingly account for different characteristics and performance in electricity resources as the energy transition continues."[39]

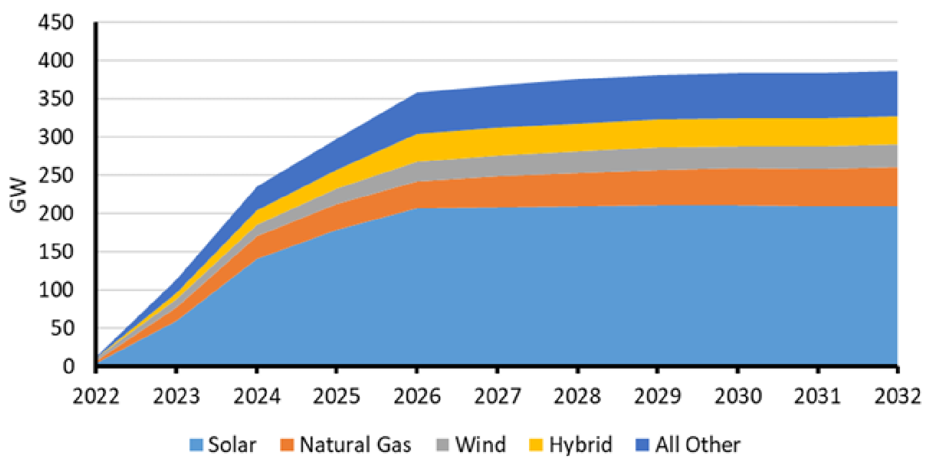

Figure 12: Tier 1 and 2 Planned Resources Projected Through 2032

The chart above from NERC December 2022 Long-Term Reliability Assessment illustrates that wind, solar and natural gas-fired generation are the predominant generation types in the planning queue looking out to

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[39] *Id.*

2032. Supply chain issues, planning and siting challenges, and business or economic factors could cause projects to be delayed or withdrawn, according to NERC's assessment.[40]

In recent testimony by NERC's President and CEO, Jim Robb, before the U.S. Senate Committee on Energy and Natural Resources, Mr. Robb echoed the findings in the Long-Term Reliability Assessment and highlighted NERC's concerns with the pace of the energy transition: "NERC is concerned that the pace of change is overtaking the reliability needs of the system. Unless reliability and resilience are appropriately prioritized, current trends indicate the potential for more frequent and more serious long duration reliability disruptions, including the possibility of national consequence events."[41] Mr. Robb noted that managing the pace of the transformation in an orderly way, including slowing the retirement of conventional generation, replacing retiring generators with new resources that can provide both energy and reliability services, and planning for "twenty-four, seven" energy instead of planning solely for capacity on peak, should be prioritized. Finally, Mr. Robb noted that while trying to ensure reliability as the generation resource mix transforms, industry, regulators, and policymakers need to balance reliability with customer affordability and environmental impacts. "When viewed through the lens of balancing reliability, economics, and the environment, the challenges for the electric sector become highly complex."[42]

In addition to NERC, PJM, MISO and other RTOs have expressed concerns about the reliability and stability of the electric grid. Specifically, PJM, the RTO that coordinates the movement of wholesale electricity in all or parts of 13 states from Illinois to Maryland and the District of Columbia, has undertaken a series of whitepapers broadly focused on aspects of the anticipated energy transition. The initial paper, "Energy Transition in PJM: Frameworks for Analysis," describes the study process undertaken whereby PJM synthesized a diverse set of PJM state policies into three scenarios in which an increasing amount of the annual energy is served by renewable generation (10%, 22% and 50%).[43] PJM concludes that there are five key focus areas for PJM's stakeholder community: 1) correctly calculating capacity contribution of generators; 2) increasing operational flexibility to address the rise in uncertainty; 3) retaining thermal generators that are essential to provide reliability services and an adequate supply until a substitute is deployed at scale; 4) using regional markets to facilitate a reliable and cost-effective energy transition; and 5) evolving reliability standards. PJM is expecting electric demand in its region to increase due to the construction of new, high-demand data centers and general electrification resulting from state and federal policies and regulations. This is

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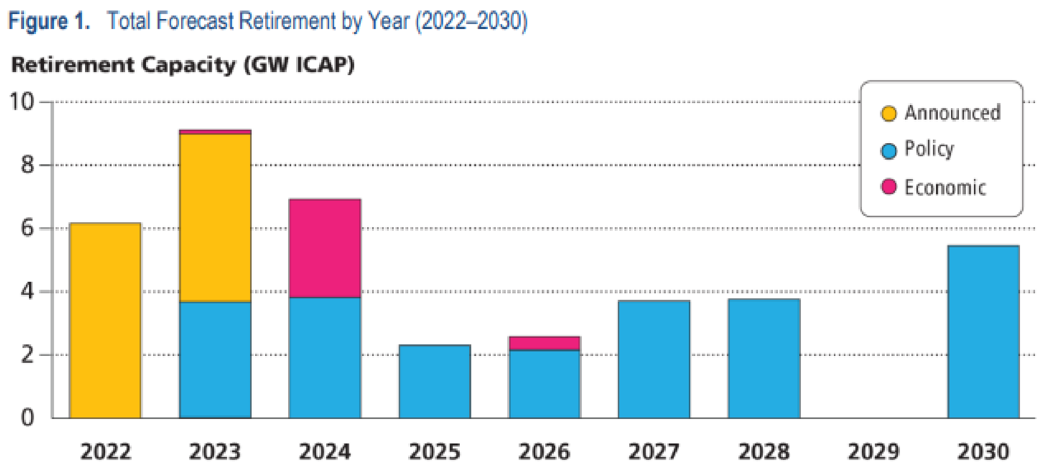
[40] *Id.* at p.15.

[41] "The Reliability and Resiliency of Electric Service in the United States in Light of Recent Reliability Assessments and Alerts." Testimony of James B. Robb, President and Chief Executive Officer, North American Electric Reliability Corporation. June 1, 2023. D47C2B83-A0A7-4E0B-ABF2-9574D9990C11 (senate.gov). p. 1.

[42] *Id.* at p. 2.

[43] Energy Transition in PJM: Frameworks for Analysis. Renewable Integration. PJM. Dec. 15, 2021. Energy Transition in PJM: Frameworks for Analysis. Last viewed August 1, 2023.

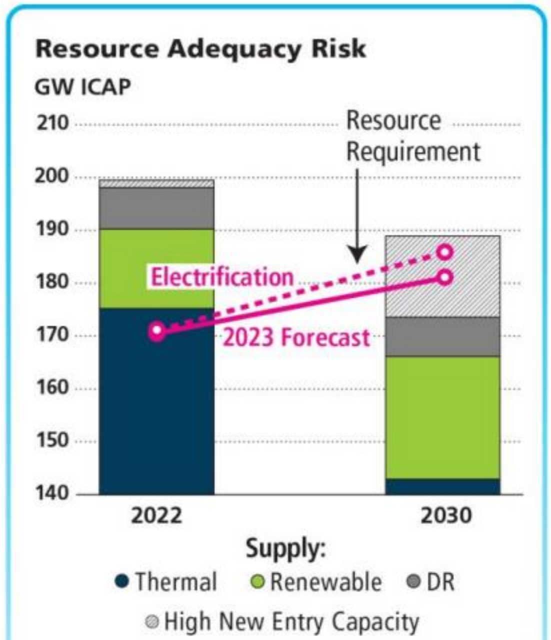
happening concurrently with the retirement of thermal generators, resulting in potential reliability issues.



The chart above from PJM's February 2023 Energy Transition in PJM: Resource Retirements, Replacements & Risks illustrates that PJM is projecting generation retirements by 2030. Combined, this represents 21% of PJM's current installed capacity.

In February 2023, PJM issued its whitepaper, *Energy Transition in PJM: Resource Retirements, Replacements & Risks*, which presents a scenario for the PJM footprint in which it "is possible that the current pace of new entry would be insufficient to keep up with expected retirements and demand growth by 2030."[44] Under one scenario studied where approximately 40 gigawatts of PJM's fossil fuel fleet resources could retire by the 2026/2027 Delivery Year, coupled with a low rate of renewable entry, the projected total capacity from generating resources would not meet projected peak loads, thus requiring the deployment of demand response. This would require the ability to maintain needed existing resources, as well as quickly incentivizing and integrating new entry. PJM highlighted the importance of continued efforts by the RTOs, stakeholders, and state and federal agencies to manage reliability impacts of policies and regulations through the energy transition where there is potential for asymmetry between resource retirements and load growth and the pace of new entry.

[44] *Id.*



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The chart above from PJM Interconnection, L.L.C., illustrates retirements due largely to environmental and legislative restrictions that have been put in place.

Similarly, MISO's 2022 Regional Resource Assessment noted that wind and solar generation are projected to serve 60% of MISO's annual load by 2041, which would reduce emissions by nearly 80 percent relative to 2005 levels, but also sharply increase the complexity of reliably operating and planning the system.[46]

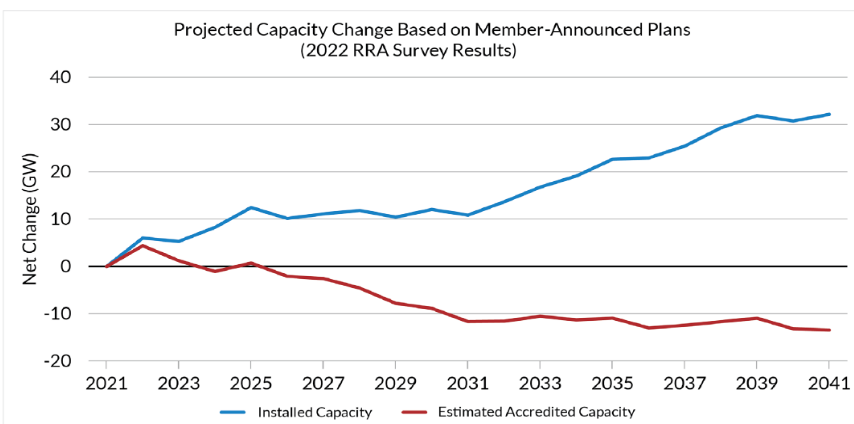

Figure 1: Projected capacity change based on member-announced plans

MISO projected capacity change based on member-announced plans[47]

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[45] *Id*. at p. 5.

[46] 2022 Regional Resource Assessment, A Reliability Imperative Report. MISO. November 2022. 2022 Regional Resource Assessment. Last viewed August 1, 2023.

[47] *Id.* at p. 3.

MISO conducted a study to assess impacts of renewables integration entitled the Renewable Impact Integration Assessment ("RIIA"), issued in February 2021.[48] In the RIIA, MISO attempted to identify new and changing risks and system needs as renewable generators are added and conventional generators retire and to develop solutions to maintain reliability and resource adequacy. Noting that, as renewable penetration increases, so does the variety and magnitude of system risk requiring transformational thinking and problem-solving, the RIIA identifies the following six categories of risks and system needs:

- **Stability Risk:** MISO notes that, as inverter-based resources displace conventional generators, the grid loses the stability contributions of physically spinning conventional units. MISO's solution is for a combination of multiple technologies to provide support, along with operational and market changes to identify and react to this risk as it occurs.

- **Shifting Periods of Grid Stress:** MISO explains that the periods of highest stress on the transmission system shift from peak power demand to times when renewables supply most of the energy and long-distance power transfers increase, making local planning and operational issues become regional challenges. Moreover, as renewable resources supply most of the energy, the system becomes more dependent on the stability attributes of the remaining conventional generators, increasing the system risk associated with unexpected outages of those generators. MISO's solution is innovation in planning and infrastructure to adapt to the new and shifting periods of stress.

- **Shifting Periods of Energy Shortage Risk:** MISO notes that risk of generation shortages is also shifting to hot summer evenings and cold winter mornings when low availability of wind and solar resources is coincident with high power demand. To address this changing risk, MISO states that (1) there is sufficient visibility of locational risk, (2) that other energy-supplying resources are available during these new times of need, and (3) there is adequate transmission to deliver power across regions.

- **Shifting Flexibility Risk:** Current flexibility is needed primarily around the morning load ramp as energy demand increases and again during the evening load ramp as demand decreases. But as solar resources meet a larger share of the mid-day demand, non-solar resources are needed to ramp down in the morning and ramp up again in the evening to balance the solar pattern and non-wind resources are needed to ramp up and down to balance wind patterns, which change daily. MISO needs increases in overall flexibility to align with the periods in which it is required.

- **Insufficient Transmission Capacity:** MISO states that the current transmission infrastructure may become unable to deliver energy to load, particularly if

[48] *Id.*

renewables are concentrated in one part of the footprint while serving load in another. MISO argues that more transmission is needed to flow power across the footprint.

The RIIA concludes that integration complexity, defined as the effort needed to plan for, support and operate new resources as they connect to the grid, increases sharply after 30% renewable penetration and significant challenges arise. MISO notes that the 30% renewable penetration milestone could occur as early as 2026.

EPA's failure to consider these complications results in an unworkable Proposed Rule that sacrifices reliability of the electric grid in exchange for full compliance. For this reason, AMP supports the concept of a reliability safety valve for inclusion in the Proposed Rule. During the course of the EPA's CPP rulemaking process, the ISO/RTO Council proposed the inclusion of a Reliability Safety Valve ("RSV") that would provide for "a reliability review conducted by the relevant system operator, working with the states and relevant reliability regulators, prior to finalization and approval of the State Implementation Plan ("SIP"). The review would identify the reliability issues and solutions. The RSV process would then provide for appropriate regulatory review and approval of the reliability assessment and solution. Next, the RSV process would accommodate the reliability solution under the CO_2 rule and/or SIP by providing for appropriate compliance and/or enforcement flexibility while a long-term reliability solution is developed and implemented."[49]

While AMP does not support that all aspects of the ISO/RTO RSV proposed in the context of the CPP should apply to this Proposed Rule, AMP believes that the concept has value in this rulemaking process where electric generator retirements as a result of the Proposed Rule could impact grid reliability. The American Public Power Association proposes a three part safety valve that would: 1) exempt EGUs that implement capacity factor limitations that permit those units to operate beyond EPA restrictions to stabilize the grid during periods of extreme load; 2) temporarily pause a compliance obligation if retail electricity rates exceed the cost of inflation specifically as a result of complying with the Proposed Rule; and 3) temporarily pause or stay compliance timelines and emission limitations if the technologies required by the Proposed Rule do not develop to the required commercial scale to the Proposed Rule deadlines. Any RSV would have to be clear enough to permit EGU owners sufficient time and clarity to make decisions about whether to continue operations. If properly structured, an RSV would provide for flexibility in enforcement of the Proposed Rule were reliability to be adversely impacted by meeting the targets within the required time frame. Moreover, if a longer-term solution is needed to ensure reliability while complying with the Proposed Rule, then an interim plan could be put in place, such as one where units could remain in operation if needed for reliability until the longer-term plan is developed and implemented. AMP supports the concept of the inclusion of an RSV in the Proposed Rule and the development of reliability solutions to guard against adverse impacts on reliability of electric service. Enforcement flexibility

[49] "EPA CO_2 Rule – ISO/RTO Council Reliability Safety Valve and Regional Compliance Measurement and Proposals," ISO/RTO Council, January 28, 2014.

that allows for interim solutions to be put in place, even if compliance is not achieved within the regulatory time frame, will ensure that longer-term solutions are established that achieve the compliance targets. Such a strategy will allow for more sustainable implementation strategies than options that sacrifice reliability. EPA should consider providing a safety valve as part of the rule to address reliability and affordability concerns.

V. The assumptions in EPA's baseline modeling analysis are flawed.

EPA relies on numerous unrealistic and unsupported assumptions, which are embedded within its baseline modeling scenario. In its baseline model, EPA projects that new renewables capacity would quadruple through 2040 from its current capacity due to IRA's financial incentives for renewable technologies.[50] However, these assumptions are likely overly optimistic and do not take into consideration barriers associated with transmission and permitting, RTO generation interconnection queue delays, as well as supply chain and construction challenges.

In addition, EPA's incorporated natural gas prices and associated supply and demand outlook differ remarkably from those provided by Energy Information Administration's ("EIA") 2023 Annual Energy Outlook baseline forecast.[51] While EIA and EPA both project large emission reductions due to IRA, EIA projections significantly deviate from that provided by EPA. EPA is projecting that only 79 TWh of coal generation will remain in 2040 —225 TWh less than EIA. Further, EPA is projecting far higher natural gas generation through the Proposed Rule's compliance period than EIA. This difference in projection between the two agencies is alarming in the context of the Proposed Rule because if EPA's projections are unrealistic, EPA's forecast results in billions of unaccounted-for regulatory compliance costs. AMP requests further evaluation of EPA's underlying supply, demand and price assumption against EIA's outlooks to address these discrepancies and ensure EPA's analysis is realistic and accurate.

Further, EPA's baseline model claims reduction in power sector emission by 80% below 2005 levels by 2040. However, with the Proposed Rule impacts through 2040, carbon emissions from the power sector are anticipated to only lower by 81% below 2005 levels. Therefore, the CCS and hydrogen co-firing requirement across the coal and natural gas generation fleet is predicted by EPA to result in an only 1% additional emissions reduction by a single industry over the next 17 years. Thus, EPA's position that the Proposed Rule is critical to greenhouse gas reduction is questionable at best, given EPA predicts its mandates will in essence be met even without regulation.

Additionally, EPA's baseline model relies heavily on changes financed with IRA available funds. EPA stresses throughout the Proposed Rule that the action was

[50] "A Closer Look at EPA's Powerplant Rule." U.S. Chamber of Commerce Global Energy Institute. June 2023, p. 5.

[51] *Id.*

developed in consideration of the potential funding that will be available through the IRA.[52] EPA's conclusion that the IRA will provide the needed funding for much of the technology-based infrastructure is speculative at best. Funding alone will not produce the predicted results, particularly in the timeframe required to meet the compliance deadlines. In fact, modeling of IRA impacts performed by Princeton University concluded that over 80% of IRA's potential emissions reductions would not occur without reforms that would enable accelerated transmission buildout.[53] Without these reforms, it is realistic to assume permitting of such facilities can take decades or more. Even with permitting reform, there is no guarantee that those subject to the Proposed Rule will secure all, or any, of the IRA funds needed to implement the proposed requirements. Additional challenges already facing the energy industry include, among others: supply chain constraints that will likely increase as projects supported through the IRA and Infrastructure Investment and Jobs Act ("IIJA") move forward; local resistance to new renewable energy development, transmission lines, pipelines, CO_2 geologic sequestration, hydrogen production and transportation, etc.; skilled workforce availability; interconnection queue backlogs, etc.

AMP's experience partnering with the federal government on incentive programs provides a cautionary tale. Specifically, in the 2010's, AMP undertook a significant generation asset development effort that resulted in the deployment of hundreds of megawatts of renewable energy, as well as traditional baseload generation, using the Build America Bonds and the New Clean Renewable Energy Bonds programs. Unfortunately, sequestration has been applied to these payments since 2013, resulting in decreased payments and costing AMP and our members more than $40 million to date. With sequestration scheduled to run through at least 2031, that cost impact is projected to surpass $80 million. The federal government cannot reasonably expect entities like AMP, who relied in good faith on funding promises so flippantly broken by federal agencies, to once again trust that government funding will be available as and when promised.

Given AMP's experience with federal government funding promises, AMP does not believe that EPA's assumption of availability of IRA funds is a safe assumption. EPA should model its Proposed Rule without assuming availability of IRA funding.

[52] 88 Fed. Reg. 33246 (May 23, 2023). "In addition, the IRA, enacted in 2022, extended and significantly increased the tax credit for CCS under Internal Revenue Code (IRC) section 45Q. As explained in detail in the BSER discussions later in this preamble, these changes support the EPA's proposed conclusion that CCS is the BSER for a number of subcategories in these proposals. In addition, in both the Infrastructure Investment and Jobs Act (IIJA), enacted in 2021, and the IRA, Congress provided extensive support for the development of hydrogen produced through low-GHG methods. This support includes investment in infrastructure through the IIJA and the provision of tax credits in the IRA to incentivize the manufacture of hydrogen through low GHG-emitting methods. These changes also support the EPA's proposal that co-firing low-GHG hydrogen is BSER for certain subcategories of stationary combustion turbines."

[53] "A Closer Look at EPA's Powerplant Rule." U.S. Chamber of Commerce Global Energy Institute. June 2023, p. 5.

VI. Concern with stranded assets

It is clear that as a result of the Proposed Rule, a number of existing coal-fired units will be forced to retire, which will result in stranded assets for which cost recovery will be a significant concern for affected entities. Stranded assets are assets that have suffered from unanticipated or premature write-downs, devaluations or conversion to liabilities.[54] If an existing EGU, which required significant capital to build, is forced to prematurely shut down and it has not yet reached the end of its useful life, then the owners of that EGU will be left with stranded assets. EGUs are capital-intensive undertakings that are planned, designed and built to last for a significant period of time, the costs of which are recovered during a long period. If an EGU ceases operation, the historical and present-day costs to build and maintain that unit do not simply go away, and there are additional costs in the form of decommissioning and the like associated with the closure.

Generally speaking, the costs associated with generating units, including the costs tied to those assets once they are stranded, are passed through to the utility's ratepayers. So, at the same time market rates will increase as a result of increased compliance costs for CCS or fuel switching and the costs associated with new generation units to replace retiring units, AMP members could also be faced with covering the costs of their own stranded assets.

How to accurately account for such stranded assets is something that has not been adequately addressed by the Proposed Rule. This failure needs to be remedied in a fair way that accurately balances the need for financial stability with reasonable rates. The Proposed Rule could turn investments—including those involving significant expenditures for environmental controls—into debt on non-performing assets that entities like AMP can pay off only through higher rates. Many of those plants were built when national policy was encouraging the use of coal as a domestic resource, and significant sums have been invested since upgrading these plants. Forcing them to prematurely shut down is an unreasonable, unjustifiable, and arbitrary outcome. To mitigate this burden of a stranded asset, a plant should be allowed to run through a transition period allowing for retirement of debt.

[54] The term "stranded cost" was developed in the context of the de/reregulation of the natural gas pipeline and then electric utility sector in the 1980s and 1990s. In the context of electric utility deregulation, generally the term has been used to refer to a cost that an electric utility is permitted to recover through its rates but whose recovery may be impeded or prevented by the advent of competition in the industry. William J. Baumol and J. Gregory Sidak, *Transmission Pricing and Stranded Costs in the Electric Power Industry*, Washington: AEI Press, 1995, 98. Amidst this deregulation, in regulating the recovery of a stranded cost FERC further clarified that such a cost must be a "legitimate, prudent and verifiable cost." 18 C.F.R. §35.26. Clearly, an electric utility's inability to recover the "legitimate, prudent and verifiable cost" of generation facility investments, of which the proposed regulations would force the premature retirement, should also be considered a stranded cost.

VII. AMP supports comments submitted by the American Public Power Association, Large Public Power Council and Prairie State Generating Company.

Due to the limited time provided to thoroughly review the Proposed Rule, AMP's primary focus has been on EPA's determination of BSER and impact on reliability and affordability of electricity. However, AMP is a member of both the American Public Power Association ("APPA") and the Large Public Power Council ("LPPC"), and an owner of the Prairie State Generating Company and supports many of the comments submitted by these entities.[55] In particular, AMP supports APPA's position that the Proposed Rule impermissibly restricts states' remaining useful life and other factors determinations. As APPA notes, Congress directed in section 111(d) that EPA "shall permit the State in applying a standard of performance to any particular source under a [section 111(d) state] plan submitted to take into consideration, among other factors, the remaining useful life of the existing source to which such standard applies." While EPA has the authority to approve or disapprove of a state plan, it cannot unduly limit a state's discretion to take these factors into account. In the Proposed Rule, EPA places so many restrictions on a state's remaining useful life analysis that states will be unable to take advantage of the ability that Congress provided them to have less stringent standards in certain circumstances. EPA's proposal that sources that have a less stringent emission limitation based on a state's remaining useful life analysis cannot participate in flexible compliance measures such as emissions averaging or trading is arbitrary and capricious and not grounded in the statute.

VIII. Conclusion

In order to reduce GHG emissions from coal-fired and natural gas-fired generation, the Proposed Rule specifies that CCS and clean hydrogen can be utilized to capture and/or significantly reduce GHG emissions, with closure of EGUs as the only other alternative. However, such an approach can only survive under CAA Section 111(d) if it is, in fact, the "best system of emissions reduction" that has been "adequately demonstrated" and is not exorbitantly costly. For the reasons set forth herein, EPA has not made such a demonstration in the Proposed Rule. While AMP supports efforts to reduce GHG emissions from the power sector, the Proposed Rule requires more consideration and discussion than EPA has allowed for under this process. The aggressive schedule set forth in the Proposed Rule provides little time for these technologies to mature and may leave fossil-based plant operators with no viable alternative to closure. As a result, AMP is concerned that the rules will contribute to a regional loss of necessary dispatchable baseload generation that will in turn have a profoundly negative impact on our ability to provide reliable and affordable electricity to AMP members and their customers. Consequently, AMP respectfully requests that EPA reconsider the Proposed Rule and allow more time and discussion for a more balanced approach to reduce GHG emissions from the power sector.

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[55] AMP's comments may differ on some issues from the APPA, LPPC and Prairie State comments. To the extent the positions and recommendations in AMP's comments differ from those expressed in the comments of APPA, LPPC or Prairie State, the positions expressed herein should be viewed as controlling.

While by no means exhaustive, the comments provided represent issues of most concern to AMP relative to the Proposed Rule. We thank EPA for this opportunity to provide input on these important matters, and we are fully prepared to assist in any effort to develop meaningful, effective and balanced GHG emission regulations.

On behalf of the Members,

Jolene M. Thompson

Jolene M. Thompson
President/CEO