ATTACHMENTS TO THE

COMMENTS OF THE POWER GENERATORS AIR COALITION ON THE U.S. ENVIRONMENTAL PROTECTION AGENCY'S 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; PROPOSED RULE

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EXAMINATION OF EPA'S PROPOSED EMISSION GUIDELINES UNDER 40 CFR PART 60

Final Report

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EXAMINATION OF EPA'S PROPOSED EMISSION GUIDELINES UNDER 40 CFR PART 60

EXECUTIVE SUMMARY

The U.S. Environmental Protection Agency (EPA) is proposing new emission guidelines for CO_2 at existing fossil fuel-fired electric generating units. The guidelines propose that the best system for emission reduction for coal-fired electric generating units is carbon capture and storage (CCS). Carbon capture rates must meet a minimum of 90%. EPA believes that CCS is a mature technology that can be implemented to meet a 2030 deadline.

Examples are given in the guidelines to show the maturity of CCS; however, these examples spotlight facilities that are small in size, and all but two examples, Saskpower's Boundary Dam Unit 3 and the Petra Nova project, perform no subsurface injection at all. The examples are of slipstream systems and production facilities. No example is given of a facility larger than Petra Nova's 240-MW facility capturing CO_2 and injecting it into the subsurface because one does not exist.

With respect to the transport and storage of CO_2, sufficient demonstration of CCS with all the appropriate regulatory frameworks in place has not occurred. Documentation is not present to support EPA's geographic analysis, and the information the Agency does possess is out of date.

The timeline for implementation of CCS is expected to take much longer than anticipated by EPA. One example is EPA review of UIC (underground injection control) Class VI permits. In the last year, the number of permits under review has risen from 9 to 98, and historically, it appears the process can take more than 6 years per permit. Overall, from evaluation to commercial operation, an optimistic timeline indicates it can take at least 7 years to complete. Any disruptions to permitting, design, or construction can extend this for many additional years, which will be incompatible with meeting compliance in 2030.

Costs related to CCS can vary widely depending on conditions at the location and the permitting required. Based on experience, the costs to design and construct the carbon capture facility can exceed $1 billion. The pipeline for transportation of the CO_2 to the injection site can cost $600,000–$2,500,000 per mile or more, with development of the injection site costing $30 million or more, depending upon the number of injection and monitoring wells required. As a result of these substantial costs, final investment decisions on the construction and commissioning of carbon capture and transportation systems are often contingent upon an associated geologic storage facility permit being available and approved. This further extends the time to implement new carbon capture and storage well beyond the proposed compliance date.

Although CCS technology is progressing, it is too early to label it as commercially mature technology, and more projects need to be completed to substantiate the performance levels suggested by EPA. Based on the supported conclusions and the current status of carbon capture technology, EGUs cannot meet the CO_2 capture rates or the timeline that EPA proposes.

EXAMINATION OF EPA'S PROPOSED EMISSION GUIDELINES UNDER 40 CFR PART 60

INTRODUCTION

The proposed change to the U.S. Environmental Protection Agency's (EPA's) rules within 40 CFR Part 60 details proposed carbon emission standards for both fossil fuel-fired steam generating units and fossil fuel-fired stationary combustion turbines. In this document, EPA outlines climate change and its impacts; recent developments in emissions; proposed requirements for both new and reconstructed stationary combustion turbine electric generation units (EGUs); requirements for new, modified, and reconstructed fossil fuel-fired steam generating units; the proposed regulatory approach for existing fossil fuel-fired steam generating units; the proposed regulatory approach for emission guidelines for existing fossil fuel-fired stationary combustion turbines; and impacts of the proposed actions. Within the document, EPA discusses the best system of emission reduction (BSER) for various subcategories of fossil fuel-fired steam generating units and subcategories of fossil fuel-fired stationary combustion turbines. The primary focus of this review is to examine the application of carbon capture and storage (CCS) technologies to these EGUs through their present state of readiness and adequacy of demonstration. CCS includes the carbon capture process itself, transportation of the CO_2, and storage or sequestration.

SUBCATEGORIZATION OF ELECTRIC GENERATION UNITS

The EPA categorizes EGU's into two primary groups: fossil fuel-fired steam generating units and fossil fuel-fired stationary combustion turbines. Various subcategories exist under the umbrella of these two categories, which are further discussed below.

Of the eleven subcategories for fossil fuel-fired steam generating units, EPA is proposing the application of CCS to one: long-term existing coal-fired steam generating units. These units are coal-fired steam generating units that have not elected to commit to permanently cease operations by January 1 of 2040. This CCS system is required to have a CO_2 capture rate of 90%, with the associated degree of emission limitation a CO_2 reduction of 88.4% lb CO_2/MWh-gross (proposed rule pages 33359 and 33360).

EPA is proposing to regulate existing fossil fuel-fired stationary combustion turbines in two segments, with only the first outlined in this proposed EPA regulation, the second to be released in a separate regulation document later. In this first segment, EPA proposes regulation for baseload turbines over 300 MW. EPA defines baseload as having a capacity factor greater than 50% (proposed rule page 33362).

EPA believes that two technologies are possible BSERs for fossil fuel-fired stationary combustion turbines over 300 MW operating at a capacity factor of greater than 50% coupled with heat-rate improvements: i) cofiring with low greenhouse gas (GHG) hydrogen and ii) CCS. EPA believes that the 300-MW threshold for applicability is appropriate because it focuses on the units with the highest emissions where CCS is likely to be the most cost-effective.

ADEQUACY AND APPLICABILITY OF CARBON CAPTURE

Several technologies are included under the umbrella of carbon capture: postcombustion, precombustion, oxyfuel combustion, and direct air capture. Direct air capture does not capture CO_2 directly from a GHG point source prior to its emission but after. Therefore, direct air capture is not further discussed, as it is not applicable to being integrated into fossil fuel-fired steam generating EGUs or fossil fuel-fired turbines.

Oxyfuel combustion involves combining a fuel, such as coal or natural gas, with pure oxygen. Since the oxidant stream is pure oxygen instead of air, such as in a conventional combustor, the combustion reaction does not create other combustion by-products such as NO_x. CO_2 and H_2O steam are produced from the reaction, which is then used to power a turbine. Since this combustion reaction creates a stream of pure CO_2, the CO_2 can be captured without the need for additional systems that are required in pre- or postcombustion CO_2 capture. However, these systems do require a constant and sizable supply of pure oxygen, often necessitating an air separator to be included in the process (1). Additional challenges of oxyfuel combustion systems are the high capital costs, energy consumption, and operational challenges of oxygen separation (2). Research of oxyfuel combustion is still ongoing, with projects focusing on lab-, bench-, and pilot-scale testing to understand the combustion mechanics of oxyfuel combustion at high temperatures and pressures, verify system design and operation concepts, and improve the performance of ancillary system components (3). Some demonstrations of oxyfuel combustion systems have been conducted, the largest being a retrofitted 100-MWth PC boiler in Central Queensland, Australia, which operated from December 2012 to March 2015. In that time, the unit achieved 10,000 hours of oxyfuel combustion and 5500 hours of carbon capture (4).

Precombustion CO_2 capture constitutes the removal of CO_2 from a fuel source prior to its combustion. This is commonly achieved through fuel gasification, in which the feedstock, such as coal, is partially oxidized with steam and oxygen-rich air under high temperature and pressure to form syngas, which is a mixture of hydrogen, carbon monoxide, CO_2, and smaller elements of other gases, such as methane. The syngas can then undergo the water-gas shift reaction, which converts the carbon monoxide and water in the gas to hydrogen and CO_2. The CO_2 can then be captured, and the H_2-rich fuel combusted. Since the precombustion fuel stream is rich in CO_2 and at a higher pressure, extraction of the CO_2 from the stream is easier than in postcombustion systems. However, the cost of a gasification system is often greater than a traditional coal-fired power plant (5). Therefore, precombustion CO_2 capture is not considered a leading technology for CO_2 emissions reduction in the electrical generation industry. But it has been shown to be effective in the chemical processing industry, with Great Plains Synfuels Plant in Beulah, North Dakota, having been in operation for the past 25 years and remaining the only coal-to-synthetic natural gas facility in the United States. Great Plains Synfuels Plant produces synthetic natural gas from lignite coal and captures its CO_2 for utilization in enhanced oil recovery (EOR) in Canada. The plant is capable of capturing up to 3 million tons of CO_2 per year. Since 2000, CO_2 emissions at the Synfuels Plant have been reduced by 45% (6).

Postcombustion CO_2 capture involves the removal of CO_2 from the flue gas of an EGU. After the fuel has been combusted, the exhaust gases are processed to filter out potential contaminants such as ash and SO_2, then the exhaust gases go to the postcombustion CO_2 capture

system, which captures the CO_2 from the gas stream through a reaction with a chemical solvent (amine). This solvent captures the CO_2 gas, and the solvent and gas are later separated in the stripper column, where heat and pressure are used to regenerate the solvent and create a stream of pure CO_2, that can then be compressed, transported, and sequestered. The use of chemical solvents for carbon scrubbing is the most commonly acknowledged process for capturing CO_2 from gas mixtures (7) and has been used in the natural gas industry to separate CO_2 from other gases since the 1930s (8). Current federally funded work in solvent-based postcombustion capture is seeking to address key challenges to deployment, which include scale-up, parasitic load, process integration, water use, and capital costs (8). Additionally, solvent degradation can be a significant issue.

The large-scale carbon capture facilities that are in operation throughout the world are mostly focused on natural gas processing (9). Only two facilities are operating at coal-fired power plants: Saskpower's Boundary Dam Unit 3 (110 MW) and the Petra Nova Project (240 MW equivalent), which will be discussed later. Postcombustion CO_2 capture has yet to be demonstrated at a baseload facility larger than Boundary Dam Unit 3. Parasitic load requirements for the operation of the carbon capture system decrease the net power output of the EGU by roughly 20% (10).

With respect to carbon capture technology, the proposed rule states that:

> *"The EPA is proposing that the CO_2 capture component of CCS has been adequately demonstrated and is technically feasible based on the demonstration of the technology at existing coal-fired steam generating units…" [page 33291]*

The design and integration of CO_2 capture facilities can vary based on the configuration of the EGU and fuel source. Variations, such as the CO_2 purity of the emission stream, facility design, local energy costs, emission volumes, flue gas temperature and pressure, the presence of contaminants, transition from cold or warm (standby) condition to operation condition, and ramping due to load changes, all affect the applicability and cost of implementing CCS at fossil fuel-fired EGUs (11). For example, in Wyoming, most of the existing power generation fleet is not equipped with environmental control systems that remove enough NO_x, SO_x, and other air pollutants to prevent the accelerated degradation of the amine solvent inside of the CO_2 capture system. 87% of EGUs have flue gas desulfurization systems, and 56% of EGUs have postcombustion NO_x control systems, whereas nearly all Wyoming EGUs only have particulate and mercury control devices installed. Before a CCS system could be constructed and retrofitted, these facilities would need to be upgraded to meet these requirements (12). These upgrade requirements are not considered by EPA in the proposed capture requirements.

Typical solvents utilized in carbon capture systems are amine-based. The name amine refers to a chemical function group that includes compounds with a nitrogen atom and a lone pair. A common amine in CCS systems is monoethanolamine (MEA), colloquially referred to in industry as amine. Amines are susceptible to degradation, and solvent management can be a significant challenge. Amine degradation can reduce solvent efficiency or cause an unintentional release into the atmosphere. This degradation can happen because of several factors: thermal or oxidative degradation or reaction with impurities in the flue gas stream. Advanced amines are being

developed, which reduce thermal or oxidative degradation of the amine and improve its capture efficiency; however, impurities still have a significant impact on the life of amine.

Thermal Degradation

The heat involved in the regeneration process, where CO_2 is stripped from the amines, can cause these molecules to break down, leading to loss of capture efficiency and the need for frequent solvent replacement. This aspect is poorly addressed in literature due to the sensitive nature of sharing specific information from vendors. This quickly increases operating costs and results in large quantities of liquid waste. The EPA does not recognize or address this issue.

Oxidative Degradation

The solubility of oxygen in amine solutions is a key issue in dealing with problems like degradation and corrosion (13). An increased level of oxygen in the amine solvent changes the solvent chemistry, increasing its tendency to cause oxidation and corrosion. The Technology Centre Mongstad (TCM) studied amine degradation in a combined heat and power plant (CHP) and noted significant corrosion. Significant material thickness reduction and leakage on the CHP reboiler heat exchanger plates were observed. The CHP stripper packing surface was coated by a layer of corrosion products. This layer was "leaching" out in the solvent upon restart of the CHP stripper, resulting in rapidly increasing iron content in the fresh solvent (14). The application of an oxygen scavenger, a chemical additive to the amine solvent, could be used as a preventive measure to keep solvent degradation low. This form of degradation of the amine solvent is correlated to the composition of the EGU's flue gas and not the capture rate of the CCS system; therefore, the effects of the flue gas on the solvent chemistry must be individually investigated at each facility.

Degradation by Reaction with Impurities

When TCM tested amines on a residue fluidized catalytic cracker (RFCC), they had not been able to operate the amine plant with RFCC flue gas because of very high amine emissions (>20 ppm) caused by sulfuric acid aerosol and dust particles present in the flue gas (15). With installation of a Brownian diffusion (BD) filter upstream from the absorber, more than 95% of the aerosols were removed, and together with optimization of plant process parameters and configuration, the amine emissions were reduced. It is known that both SO_2 and NO_x will give unwanted reactions with MEA (16).

Although the degradation mechanisms for MEA have been extensively studied in the literature (16–19), testing, understanding, and mitigating amine degradation on a plant-by-plant basis are crucial for the sustainable and efficient application of CCS technology. Research is ongoing to develop advanced amines and to improve the process design to minimize amine losses, such as optimizing operating conditions, implementing solvent purification processes, and better managing impurity variability in the flue gas.

The above discussion illustrates that additional investigation is required at the specific facility being considered for installation of a carbon capture system that may include significant construction and redesign to accommodate CCS implementation.

CARBON CAPTURE EXAMPLES

EPA cites several examples of successful plant operation within its proposed guidelines, and a few of them will be briefly discussed. These examples do show that CCS is possible and promising and present a promising solution for the future; however, they do not reflect the needs as set forth by EPA as they are examples of slipstream systems, are smaller capacity units, do not employ the full CCS process, and are capturing CO_2 at levels below 90%.

AES Corporation's Warrior Run Generating Station

The Warrior Run Station is a 180-MW bituminous coal-fired power plant located in Maryland. The installed CO_2 capture system captures a small slipstream of the facility's flue gas to produce 330 t CO_2/day of food-grade CO_2 for use in food processing. The process used is an ABB Lummus unit with MEA as its solvent (20). The installed CO_2 capture system captures anywhere between 4% to 6% of the CO_2 emissions of the plant (21). The important highlights are that the system is a slipstream of a small power plant which produces a product and does not inject CO_2 into the subsurface. Therefore, the small capacity, slipstream system employed here demonstrates a small portion of the required CO_2 capture rate and has little correlation to the levels EPA would mandate under their proposed guidelines.

AES Corporation's Shady Point Generating Station

Shady Point Power Plant is a 320-MW circulating fluidized-bed subbituminous coal-fired power plant located in Oklahoma. A slipstream of the power plant's flue gas is captured to produce 200 t CO_2/day of food-grade CO_2 for use in food processing. With the plant emitting 1.24 million t CO_2/year, the yearly capture rate approximates to 6%. This process uses an ABB Lummus scrubber system with MEA as its solvent (20). Like the Warrior Run Generating Station, this is a small slipstream which produces a product and does not inject CO_2 into the subsurface. This example has little correlation to the levels EPA would mandate under their proposed guidelines.

Searles Valley Minerals Soda Ash Plant

The Searles Valley Minerals Soda Ash Plant, located in California, captures approximately 800 t CO_2/day from the flue gas of the 62.5-MW Argus Cogeneration Plant, a subbituminous coal-fired power plant that generates electricity and steam. The CO_2 is captured with an ABB Lummus MEA capture unit, and the captured CO_2 is used for the carbonation of brine in the production of soda ash (20). With the plant emitting 1.63 million t CO_2/year, the capture rate approximates to 18%. Like the previously discussed facilities, the small capacity system employed here demonstrates a small portion of the required CO_2 capture rate and has little correlation to the levels EPA would mandate under their proposed guidelines. The correlation between this facility and what is expected under the proposed guidelines is minimal.

Quest CO_2 Capture Facility

The Quest Carbon Capture and Storage Project is a CCS facility in Alberta, Canada, that began operation in 2015. Quest removes CO_2 from the process gas streams of three hydrogen

manufacturing units (HMUs), equating to 1 million t CO_2/year, within the Scotford upgrader facility, which emits 3 million t CO_2/year. Between the years of 2015 and 2021, Quest has been able to capture between 77.4% and 83% of CO_2 emissions from the HMUs, with the average CO_2 capture rate of 79.4% (22). Although the facility has demonstrated the ability to store CO_2, the overall capture rate of the facility falls short of EPA's proposed 90% minimum capture rate.

Saskpower's Boundary Dam Unit 3

Saskpower's Boundary Dam Unit 3 (BD3) is a 110-MW lignite-fired unit in Saskatchewan, Canada. Development of the CCS facility began in 2007, with the decision to move forward with construction in 2010, and provides CO_2 for both EOR and sequestration. Saskpower selected the CANSOLV process, an amine solvent system, for its CO_2 capture process. During its first year of operation, BD3 achieved a CO_2 capture rate of 50% of its designed volume. This capture rate has been improved through design and operations optimizations, although the capture rate is still below its designed CO_2 production levels. Significant issues included operational difficulties from construction and design deficiencies, issues with fly ash carryover, a lack of redundancy and isolation capabilities, and amine degradation and foaming (23). Lessons learned from this CCS facility are slow to be released, and there may be other operational challenges that industry and EPA do not know about. This facility exemplifies the site-specific challenges that are to be expected with CCS implementation and is only one-third the scale of plants that would be addressed in EPA's proposed emission guidelines.

NRG Energy's Petra Nova Facility

The Petra Nova facility, located in Texas, is a 240-MW equivalent slipstream of flue gas from the W.A. Parish coal-fired facility. This postcombustion capture facility started operation in 2017 and fulfilled its objectives of demonstrating carbon capture at this scale coupled with compression and transportation of CO_2 to an oil field for EOR only. The facility was shut down because of low oil prices in May 2020 due to no alternate method of sequestration. Market-driven EOR alone does not adequately demonstrate CCS that will meet EPA's proposed continuous emission reduction. During its 3-year operation, it suffered frequent outages and missed its carbon capture targets by ~17% (24).

AVAILABILITY FACTOR

The availability factor is a measure of the amount of time a system is in operation and not undergoing maintenance, repair, and unexpected down time and is given as a percentage. The most relevant example given by EPA for an EGU utilizing a fully integrated carbon capture system is Boundary Dam Unit 3, as mentioned above. Since its start-up in 2014, the unit has experienced operational issues that have led to more frequent capture facility outages than originally anticipated. The primary issues experienced have been with fly ash and fly ash component buildup in the CCS facility. Heat-transfer surfaces, such as the reboilers, fouled over time. The packing in the absorbers and the strippers also experienced fly ash buildup and the development of organic deposits. These issues affected the capture capacity of the facility as the heat-transfer efficiency decreased and the gas flow rate became limited because of deposits. The implementation of

advanced demister wash systems has extended the facility's operational time between maintenance outages, and wash systems for the booster fan and redundant heat exchangers, with isolations, have enabled the facility to conduct online maintenance. The capture facility has also experienced compressor failures that increased its unplanned outage time for the years of 2021 and 2022. Figure 1 shows the yearly percent availability of the Boundary Dam Unit 3 capture facility's availability, planned maintenance outages, and unplanned outages for the years of 2014 through 2022 relative to the operation of the power plant (25).

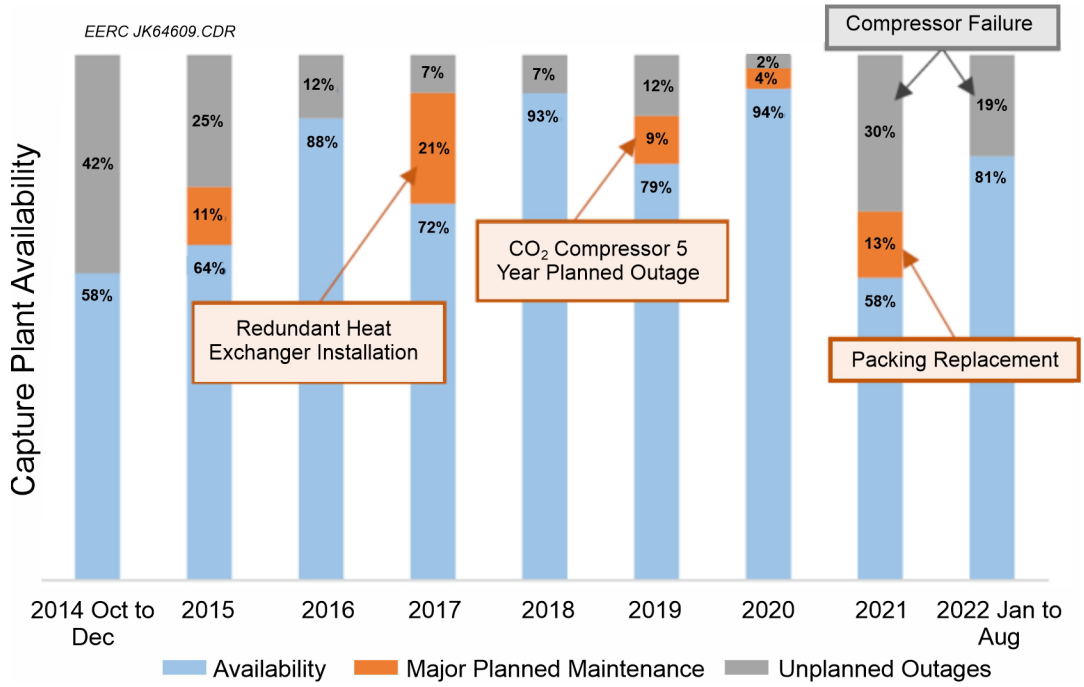


Figure 1. Availability of Boundary Dam Unit 3 capture facility and CO_2 compressor relative to the Unit 3 power plant (25).

The figure shows that annually the capture facility was not able to operate the full time the power plant was in operation and for only 2 years was the facility operating above 90% of the available time. Based on this information, even with the capability to capture greater than 90% of the CO_2 emissions, it is premature to expect that a capture facility will be able to operate with an availability factor sufficient to comply with the annual emission requirements of the proposed rule.

NATURAL GAS CARBON CAPTURE

Many of the demonstrations studied by EPA are coal-fired power plants with small slip stream CO_2 capture systems. EPA proposes CCS as the BSER for stationary combustion turbines for greater than 300 MW and over 50% capacity factor; however, CCS has been studied less at natural gas EGUs than coal-fired EGUs. Among coal-fired EGUs, each facility has different CCS retrofitting and integration needs, due to the operational parameters, facility differences, and the

composition of flue gas. One of the primary challenges with natural gas is its lower carbon load. Natural gas-fired generation produces less CO_2 per MWh than coal-fired facilities, meaning that the capture plant design has to be adjusted for a lower concentration of CO_2 in the flue gas (26). Additionally, gas turbine EGUs are more likely to be throttled for load-following applications than coal-fired EGUs, adding significant demands and stresses on the attached CCS system to ramp with the power plant (27).

INTEGRATED GASIFICATION COMBINED CYCLE (IGCC)

Currently, no commercial-scale IGCC plants are in operation or under development. The Kemper County, Mississippi, IGCC project struggled, with major problems stemming from overly complex technology, complex supply chain, and equipment reliability issues (28). After significant cost overruns, the original plan for a gasification plant was abandoned, and the plant was converted to natural gas operation (29).

TRANSPORTATION AND GEOLOGIC STORAGE

Several fundamental assertions are made by EPA in its proposed guidelines in relation to CO_2 transportation and geologic storage. In the following sections, those assertions will be directly addressed.

With respect to the geologic storage of CO_2, the proposed rule states that:

> *"The EPA proposes that CCS at a capture rate of 90 percent is the BSER for long-term coal-fired steam generating units because CCS is adequately demonstrated, as indicated by the facts that it has been operated at scale and is widely applicable to sources and that there are vast sequestration opportunities across the continental U.S." [page 33346]*

The issue is with the assertion that "CCS is adequately demonstrated" and "has been operated at scale." EPA describes in the May 23, 2023, technical support document (TSD) titled *GHG Mitigation Measures for Steam Generating Units TSD* on page 22 that there are only two large-scale CCS facilities in North America on existing coal steam EGUs. One of which was Petra Nova which only operated from 2017 to May 2020 and involved CO_2 EOR. The other is Boundary Dam in Canada, which is not subject to EPA's underground injection control Class VI rules for the storage of CO_2. To date, no commercially operated CCS project capturing CO_2 from a coal steam EGU in the United States has operated under EPA Class VI regulations. The only CCS projects that are in operation in the United States under EPA Class VI regulations are Archer Daniels Midland processing plant (capturing approximately1 million tonnes/year) in Decatur, Illinois, and the Red Trail Energy ethanol facility (capturing approximately 180,000 tonnes/year) near Richardton, North Dakota. For comparison, a 300-MW coal-fired facility would capture approximately 2.5 million tonnes/year. These two projects are not enough to demonstrate that the appropriate regulatory frameworks are in place for the operational phase of projects that will require flexibility and likely regular updates to permitted operational parameters.

Another issue is with the assertion of "vast sequestration opportunities." This assertation is seemingly founded on a geographic analysis performed by EPA:

> *"The EPA performed a geographic availability analysis in which the Agency examined areas of the country with sequestration potential in deep saline formations, unmineable coal seams, and oil and gas reservoirs; information on existing and probable, planned or under study CO_2 pipelines; and areas within a 100-kilometer (km) (62-mile) area of locations with sequestration potential." [page 33298]*

However, no documentation of this geographic analysis is provided. The May 23, 2023, TSD titled *GHG Mitigation Measures for Steam Generating Units TSD* also referenced this geographic analysis. Figure 1 of the TSD showing geologic storage potential from the NATCARB website includes an antiquated map layer for unminable coal seams. The U.S. Geological Survey (USGS) has a more accurate map of unminable coal seams that could be used for CCS (30). The USGS map accounts for EPA Class VI regulations, 40 CFR 144.3, and 40 CFR 144.6 (31), which prohibit CO_2 storage in formations with salinity lower than 10,000 mg/L (30, 32). Figure 1 of the TSD also shows an erroneous map layer for deep saline formations. Using the correct deep saline formation map layer (showing the proper extent of assessed formations based on minimum depth requirements), the USGS coal layer, and the pertinent stationary CO_2 sources will show that the spatial relationship of CO_2 capture to geologic storage is not as opportune as suggested by EPA. The result is that more and longer pipelines will be needed to transport captured CO_2 to feasible storage locations. This implication cascades into additional time (and money) needed to construct a fully integrated CO_2 capture, transport, and storage project. Other aspects of EPA's geographic analysis that contribute to the overstatement of "vast and nearby" geologic storage opportunities are:

- Proximity does not factor into the feasibility/suitability of geologic storage.

- The EPA geographic availability analysis is based on a generation unit being within 100 km of a state with geologic storage potential, rather than from the storage location itself, which erroneously oversells the spatial relationship between CO_2 source and geologic sink.

- The analysis does not integrate evolving local (state, county, parish) CO_2 transportation and storage laws, some of which are looking to ban the geologic storage of CO_2.

In the TSD, EPA states:

> *"DOE's assessment focuses on the potential physical constraints for sequestering CO_2; it does not include economic or other constraints."*

And

> *"While the NETL and USGS characterize potential storage, site-specific technical, regulatory, and economic considerations will ultimately factor into the attractiveness of a given storage resource for a particular project."*

These are nontrivial comments that have a strong impact on project timelines and budgets when a geologic storage option is pursued for captured CO_2. A major consideration from a regulatory perspective is access to federally owned pore space, a topic that has yet to be fully addressed by any federal agency.

TIMING

In the May 23, 2023, TSD titled *GHG Mitigation Measures for Steam Generating Units TSD,* EPA denotes that deployment of CCS is economically reasonable and can be done within 5 years:

> *"Deployment of CCS technology at EGUs involves a project schedule that can be completed in roughly five years. For affected sources who choose to implement CCS, the project will involve several phases, many of which can occur concurrently and simultaneously." [page 35 TSD]*

> *"There are many site-specific considerations to individual sources that influence the project timeline and schedule. Nonetheless, EPA believes that a five-year project timeline for deploying CCS, and related infrastructure and equipment, is reasonable." [page 36TSD].*

This 5-year period, as depicted in the example timeline shown in Figure 2, which was also presented in the TSD, is not realistic and is completely unachievable. The timeline has several issues related to the sequencing of events, as discussed below.

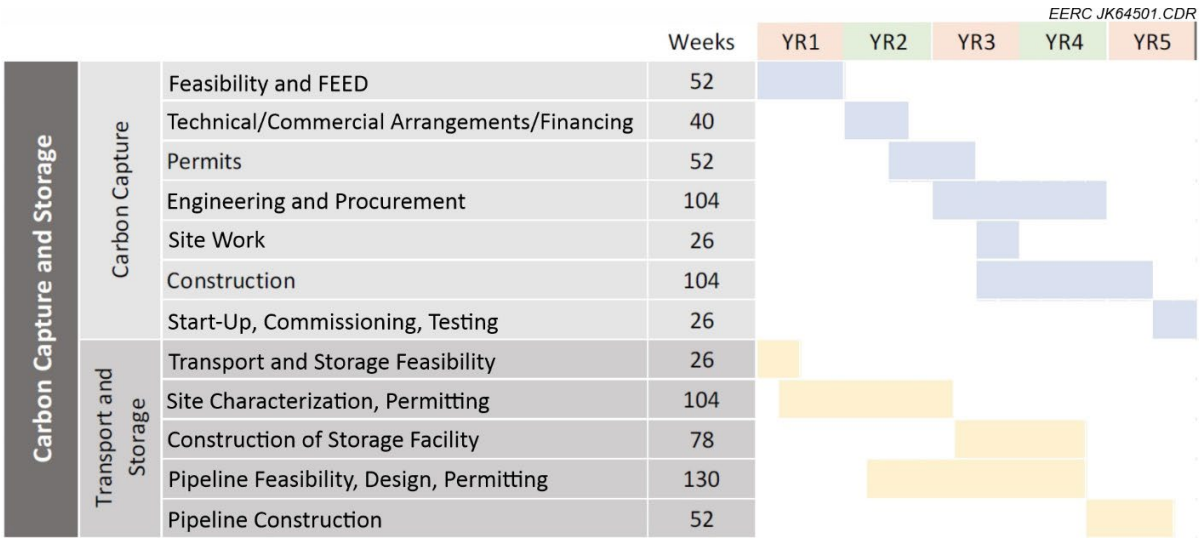


Figure 2. Timeline to storage as presented by EPA in the TSD.

Carbon Capture Timing Issues

This timeline assumes that procurement of capture equipment will be started prior to the storage site being permitted. Most facilities looking to develop CCS will be reliant on third-party financing or loans. These financing avenues have historically required permits for the storage site to be in place to increase regulatory certainty and reduce investment risks. Based on that experience, even on EPA's inaccurately short and overlapping time frames for each step, the carbon capture timelines would be delayed by at least an additional 1.5 years.

The timing of the site work and construction at the carbon capture site are shown to commence approximately 6 months after the start of engineering and procurement. Without detailed information concerning the constructability of the site such as soil analysis, location parameters (temperature changes, wind loading, etc.), the footprint of the capture facility, etc., that requires measurement and testing to provide detailed information for the construction of the capture facility, the present timeline is likely compressed and would be expected to require additional time (3–6 months) to complete the requisite evaluations prior to initiation of work.

Transport and Storage Timing Issues

The timeline shown in Figure 2 depicts 2.5 years for storage feasibility, site characterization, and permitting. This is an extremely optimistic and aggressive timeline. For example, the U.S. Department of Energy's CarbonSAFE Program assumes a 5-year timeline to address feasibility, characterization, and permitting. Even for states with Class VI primacy such as North Dakota, storage feasibility, site characterization, and permitting could take up to 4.5 years (33). One of the only ways to accelerate this timeline would be if there were existing site-specific data that were sufficient to address UIC Class VI requirements. For states without primacy, storage feasibility, site characterization, and permitting could take up to 6.5 years based on historical EPA permitting timelines from the two approved EPA UIC Class VI permits (34). In June of 2022, nine projects were waiting for Class VI permit approvals (35). EPA now has 98 UIC Class VI permits (in 35 projects) to review (36).

Another issue with the proposed 5-year timeline is that it does not adequately factor in the time needed to lease pore space. Much of the prime geologic storage opportunity lies beneath federally owned lands. As such, any storage operation that will emplace captured CO_2 in pore space managed by the federal government will need to work through federal permitting and NEPA (National Environmental Policy Act) review. This process alone can add years to a project's development timeline. In addition to the federal land issue, many states have yet to address pore space ownership. Challenges to amalgamation authority on nonfederal land, achieving 100% consent of private pore space owners where amalgamation rules do not exist, and states lacking established pore space rules result in significant uncertainty regarding how much of the nation's geologic CO_2 storage resources can be developed and permitted, particularly within the time frame of the proposed rules.

Pipeline feasibility, design, and permitting stage is listed at 2.5 years. Depending on the route of the pipeline, permits for water body crossings, federal lands, and the Army Corps of Engineers can take a year or more to acquire, if the permit is allowed at all. In addition, agreements with

landowners for rights of way (ROWs) for the pipeline can take a year or longer, depending on the length of the pipeline. In all, the listed time of 2.5 years for pipeline feasibility, design, and permitting appears to be overly optimistic. In addition, with the current supply chain issues, the ability to secure the required piping and equipment may take up to 1 year to acquire. With multiple major projects planned to be undertaken, supply chain issues would be expected to worsen. Finally, as the number of projects grow, the demand for labor will increase, adding to the expected cost.

A subsidiary supporting attachment provided by EPA to augment the *GHG Mitigation Measures for Steam Generating Units TSD* entitled "CCS Schedule Sargent and Lundy" contains the development timeline in Figure 3. As stated in the supporting document, "This schedule is for the on-site CCS system only and does not include the scope associated with the development of the CO_2 off-take/storage (including transportation, sequestration, EOR, utilization, and/or utilization)." Although the 7-year schedule shown in Figure 3 is quite aggressive, it is more realistic than the EPA's schedule shown in the upper part of Figure 2. There is no explanation as to why EPA chose to arbitrarily dismiss this timeline in favor of one that seemingly fits its regulatory goals better.

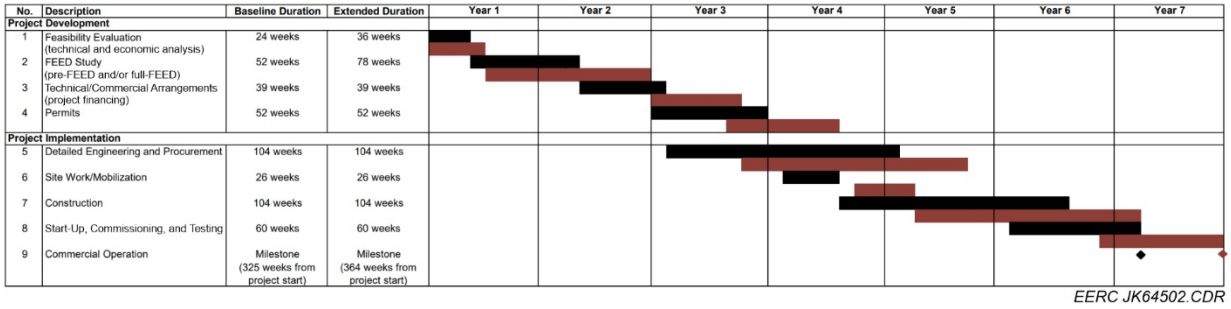


Figure 3. More realistic development timeline for the capture portion of a CCS project.

COSTS

It is difficult to give precise costs for a CCS project because of the factors outlined above and the specific needs of a specific facility to achieve a minimum of 90% CO_2 capture. It has been our experience that the general range for the capture facility at EGUs alone is $0.8–$1.3 billion. In determining the needs for CO_2 transportation, a "rule-of-thumb" (ROT) estimate for the installed cost of a pipeline can be calculated with the following expression:

Installed Cost = Pipe O.D. (inches) × Pipeline Length (miles) × $100,000

This ROT estimate is a based on the FECM/NETL CO_2 Transport Cost Model (2022) (Model), where the installed cost reflects 2019 dollars and is based on the Parker equation within the central U.S. region, referenced within the Model. Pipelines in other areas as well as any pipeline specific needs (environmental impacts, water body crossings, large elevation changes, etc.) would need to be addressed in addition to the estimated costs provided by the Model. The Model reflects costs for new pipeline installations and reflects the steel pricing used within the model. If the

pricing of steel for the pipeline under consideration is different than the pricing included in the Model, the Model would need to be adjusted to reflect the current pricing or additional cost included to reflect the anticipated pricing.

EPA references $280K per inch-mile for pipeline installations and states that is the cost "to construct new natural gas pipelines ("laterals") and is an average for lateral development within the contiguous U.S." (page 33353). The term "lateral" typically refers to a line that delivers product from a main line to a customer. As such, the installation of a lateral will normally include costs such as hot tapping of the main line to install the lateral offtake, potentially shutting down the main line to install the lateral offtake, etc. These are high-cost projects and are not typically included in new pipeline construction.

From our experience in CCS field development, using an example of one injection well with one monitoring well, assuming the CO_2 is at pressure and not requiring additional pressurization at the injection pad, and injecting 1 million metric tons of CO_2 per year, the cost of injection field development surpasses $30 million. Additional injection and monitoring will cause this value to quickly increase. Also, the need for premium casing such as corrosion-resistant alloys (CRAs) can add substantial cost to the drilling costs associated with the injection and monitoring wells necessary for the project. In addition, the lead time for the CRA material can be 1 year or longer. If material testing is required to determine which CRA would best serve the system, the time to design, perform, and evaluate the material tests can require 6 to 12 months (depending on the number and types of materials for testing) before the CRA material can be purchased. Given the wide range of CO_2 streams from the EGU and other facilities, different targeted injection horizons, and very little information available on CRA testing in saline environments with CO_2 streams with multiple impurities, it is anticipated that material testing would be required to determine which CRA material would be required. The effects that the material testing needs and the availability of CRAs would have on a project are not evident in EPA's consideration.

SUMMARY

Although CCS technology is progressing, it is too early to label it as commercially mature technology, and more projects need to be completed to substantiate the performance levels suggested by EPA. No large-scale (greater than 240-MW) CCS systems on EGUs are in operation in the United States by which to determine the feasibility of CCS as a BSER option. Each facility's design considerations are unique and can vary widely due to variables such as the CO_2 purity of the emission stream, facility design, local energy costs, emission volumes, flue gas temperature and pressure, the presence of contaminants, transition from cold or warm (standby) condition to operation condition, ramping due to load changes, and the required purity of the CO_2 emission stream. When examining the case of Boundary Dam Unit 3 capture facility's availability factor, since the start of operation, the expectation of a capture facility to operate long enough through the year to meet EPA's proposed annual emission requirements has fallen short, and there is no expectation that facilities in the United States will not see similar issues. The EPA storage assumptions are not adequately documented, and the complexity of the permitting required will greatly affect timelines for facilities to implement CCS. Based on the supported conclusions and

the current status of carbon capture technology, EGUs cannot meet the CO_2 capture rates or the timeline that EPA proposes.

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Attachment E

Analysis of Post Combustion CO_2 Capture, Transport and Storage Costs in the EPA's Proposed Power Plant Greenhouse Gas Emissions Rule

Regarding: EPA's Proposal 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"
(Docket EPA-HQ-OAR-2023-0072)

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August 3, 2023

Executive Summary

The EPA issued proposed rules for greenhouse gas (GHG) mitigation from the electric power generating sector under Clean Air Act Section 111 ("proposed rules") in May of 2023. While these proposed rules include alternative potential compliance methods, including retirement, for achieving the targeted GHG reductions, the focus of this analysis will be the cost of implementing post combustion CO_2 (carbon) capture and storage (CCS) in natural gas- and coal-fired applications.

In the proposed rules, natural gas combined cycle (NGCC) power plants opting to implement CCS would be required to do so by 2035 and coal would be required to implement CCS by 2030. As part of its determination of which is the "best" system for emissions reduction (BSER), the EPA has an obligation to consider cost. Consequently, the EPA has provided technical support documents to determine the cost of CCS implementation in coal- and gas-fired applications.

However, the technical support documents are inconsistent with each other, as well as the many references from which the EPA selectively retrieves costs without appropriate context and without noting key differences in many modeling assumptions. Furthermore, the EPA does not adequately address how the social cost of carbon is calculated, what modeling assumptions were used, and how these costs compare to much more representative cost modeling associated with real plants in various regions across the United States operating in a very complex interconnected electrical generation, transmission, and distribution system.

In addition, the EPA fails in its cost modeling to adequately address how the Internal Revenue Code (IRC) section 45Q tax credit works in practice. The tax credit is a credit against income tax, but the EPA treats it as a direct and immediate discount to the cost of building and operating a CCS system. Such treatment shows that the EPA has failed to accurately apply basic financial modeling or account for the actual regulations of other federal agencies.

For these reasons, the only possible conclusion is that the EPA is significantly underestimating the cost of compliance of this proposed rule, using flawed modeling and a lack of a transparent social cost of carbon.

Modeling and Cost Inconsistencies Applicable to Natural Gas and Coal-Fired Applications

In docket EPA-HQ-OAR-2023-0072, the EPA provides two primary technical support documents regarding CCS. The first, *Greenhouse Gas Mitigation Measures Carbon Capture and Storage for Combustion Turbines* applies to NGCC applications over 300 MW.[1] The second is for coal

[1] *Greenhouse Gas Mitigation Measures Carbon Capture and Storage for Combustion Turbines*, Accessed 7/7/23, Available at: https://www.epa.gov/system/files/documents/2023-05/TSD%20-%20GHG%20Mitigation%20Measures%20for%20Combustion%20Turbines.pdf

applications, *Greenhouse Gas Mitigation Measures for Steam Generating Units*.[2] Both documents provide technical explanations and cost modeling for CCS in their respective applications.

However, there are some glaring inconsistencies. First, the assumed cost of transportation, storage, and monitoring (TS&M) is assumed to be $10/ton in natural gas-fired applications, but $30/ton in coal-fired applications. Clearly, a ton of CO_2 meeting the same pipeline quality specification should cost the same to transport, store, and monitor, regardless of the source. Such a blatant, threefold inconsistency in the same number in the two primary technical support documents indicates that the EPA has inexplicably failed to apply consistent methodologies for addressing the same question, resulting in glaring inconsistencies that lead to arbitrary and capricious results and analyses. Given the importance of such a regulation, the EPA should at least hold itself (and be held) to the most basic standards of consistency, which have not been met in this proposed rule.

Furthermore, in both cases, the EPA cites the National Energy Technology Laboratory's (NETL) *Quality Guidelines for Energy System Studies: Carbon Dioxide Transport and Storage Costs* (QGESS).[3] That study is stated in 2018$ and there is no evidence that the EPA costs have been updated to 2023$, which would be subject to a 21.1% cost increase due to inflation. Thus, not only has the EPA used vastly different numbers, but these costs are also significantly discounted related to the costs that would be incurred in 2023.

In addition, the referenced QGESS report finds that the four geological formations in the study have a broad range of characteristics that affect cost of injection of CO_2 and the capacity of the formation to accept CO_2. The EPA technical documents do not acknowledge the wide range of costs associated with injection depending on geography and geologic conditions, and EPA instead simply assumes a single cost number for injection and a single 100 km transportation distance. With those generalizations, it is impossible to determine how either $30/ton or $10/ton are extracted from the referenced QGESS document. The numbers appear to be completely arbitrary and yet are extrapolated to the entire country.

As an example, the referenced QGESS document studies include geologic assessments in Illinois, North Dakota, Wyoming, and Texas. The first-year break-even cost of injection, not including transportation costs, varied from $8.32 to $19.84 per metric ton of CO_2. These four geological formations are all in the central part of the United States. As such, the EPA's assumed 100 km transportation distance fails to adequately account for the actual distance necessary for most CO_2 to reach a sequestration site from existing or new generation sites throughout the country, as well as the variability within the country on storage costs. In the case of the NGCC technical supporting document, the EPA assumes a $10/ton cost to transport and store CO_2, when in the same QGESS document referenced by the EPA, the federal government's own data indicates double that cost just for storage without any transportation of CO_2 in Montana.

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[2] *Greenhouse Gas Mitigation Measures for Steam Generating Units*, Accessed 7/7/23, Available at: https://www.epa.gov/system/files/documents/2023-05/TSD%20-%20GHG%20Mitigation%20Measures%20for%20Steam%20EGUs.pdf

[3] *Quality Guidelines for Energy System Studies: Carbon Dioxide Transport and Storage Costs*, Accessed 7/7/23, Available at: https://www.netl.doe.gov/projects/files/QGESSCarbonDioxideTransportandStorageCostsinNETLStudies_081919.pdf

It should also be noted that the QGESS costs do not specifically mention a direct cost for accessing the pore space. Pore space owners will require compensation for allowing a company to utilize that property, and this fact and associated cost are not adequately identified or included in the EPA's documents. Significant variability could be expected in terms of pore space lease fees associated with surface ownership rights, as it cannot be guaranteed that surface rights landowners would be willing to lease subsurface storage rights at a given cost, or if subsurface rights could even be procured due to landowner concerns.

Finally, as has been publicly demonstrated in Iowa, recent attempts to build CO_2 pipelines to industrial facilities have met severe resistance.[4] The EPA's notion that a 100 km CO_2 pipeline is feasible for all units not only ignores the geographic reality that most power plants in the country are further than 100 km from a storage site, but also erroneously assumes that pipelines crossing private property would be feasible, guaranteed, or constructed in the proposed timelines required.

Fundamental Flaws in Cost Modeling

The EPA also has fundamental flaws in cost modeling that apply to both natural gas- and coal-fired applications. In both the natural gas- and coal-fired technical support documents, the EPA provides various cost estimates and models for various applications. The EPA also has fundamental flaws in cost modeling that apply to both documents. Additionally, every single example that the EPA provides assumes that the enhanced IRC Section 45Q tax credit provides an immediate $85 per metric ton discount to each metric ton of CO_2 captured and securely stored. The EPA also does not acknowledge the severe barriers to obtaining, transferring, and utilizing the tax credits that would reduce that value for unit owners and thus result in higher than assumed costs.

EPA Cost Estimate Flaws in Coal Fired Applications

In the technical support document, *Greenhouse Gas Mitigation Measures for Steam Generating Units*, the EPA references a report by the Global CCS Institute (GCCSI), *Technology Readiness and Costs of CCS,*[5] indicating that costs of CCS on coal-fired applications have been steadily dropping and would approach $50 per metric ton by 2025. However, this was assuming a 90% generating capacity factor for coal-fired units and 100% availability of their capture system in the GCCSI report. In contrast to the 90% generating capacity factor used in the GCCSI modeling, the EPA's modeling used a variety of capacity factors, including 40% and 70% for the host unit, while assuming that the capture system has 100% availability when the host site is running. The Energy Information Administration's (EIA's) measured and recorded capacity factor data indicates an average coal-fired capacity factor of 47.8% for the year 2022.
As the EPA concedes, increasing unit capacity factors substantially decreases the cost per ton of CO_2 captured. Therefore, the EPA's referenced $50 per metric ton of CO_2 captured is not

[4] "Iowa House passes new limits on when carbon pipeline companies could use eminent domain," Accessed 7/19/2023, Available at: https://www.desmoinesregister.com/story/news/politics/2023/03/22/iowa-house-passes-bill-restricting-eminent-domain-to-build-pipelines/70035687007/

[5] *Technology Readiness and Costs of CCS*, Accessed 7/7/23, Available at: https://www.globalccsinstitute.com/wp-content/uploads/2021/03/Technology-Readiness-and-Costs-for-CCS-2021-1.pdf

reflective of its own modeling parameters (i.e., capacity factor), much less real-world conditions. The EPA should not cherry pick costs completely out of context from independent reports to justify its rules. Instead, the EPA should reevaluate its cost models using a consistent methodology and consistent capacity factor assumptions based on real data, rather than hypothetical reports with significant differences in baseline assumptions.

Additionally, the EPA's and GCSSI's assumptions related to 100% availability of CCS systems is fundamentally flawed. For example, the EPA justifies CCS on coal units as BSER by referring to Sask Power's Boundary Dam project in the EPA's *Greenhouse Gas Mitigation Measures for Steam Generating Units* technical support document. The EPA states, "In the 4th quarter of 2022, the CCS unit was available 78.9% of the time and had exceeded its target availability of 75% for three consecutive quarters." On the other hand, if a capture system is only available 75% of the time, clearly the 90% coal unit capacity factor as assumed in the referenced GCCSI model is impossible and should not be referenced in the first place.

Such limited capture system availability also makes even a 70% capacity factor for the host plant highly improbable. The proposed rule by the EPA would require the capture system to be available whenever the host site generates power to achieve 90% capture of CO_2 emissions. If the capture system has an availability of 75%, the absolute maximum capacity factor for the host site would be 75%. An availability of 75% for the CCS system means that the power plant is not allowed to operate 1 in 4 days, or for 91.25 days per year, in a best-case scenario. This poor availability of the CCS system should be used to reference why CCS is not BSER, rather than why it is BSER. Based on the EPA's proposed rule, it is unlikely that Boundary Dam's current performance would be in compliance with the proposed rule without significant limitations to its capacity factor.

This challenge with inconsistent capture system availability and modeling over a wide range of host unit capacity factors also ignores some very real technical challenges implicit in the capacity factor numbers. As the EIA reported, the 2022 average capacity factor for the coal fleet was 47.8%. This indicates that coal plants are not operating at high capacity factors and are also operating at part load or in load following modes. The EIA's data reflects this reality, that actual coal-fired power plants operate in a dynamic mode on a dynamic grid where they may be required to operate at near 100% capacity factor or 40% capacity factor, depending upon the needs of the grid at any given time.

When this happens, the partial pressure of the CO_2 in the flue gas fluctuates and is reduced under low load conditions, typically also accompanied by a reduction in efficiency and higher heat rate. When units change load, the partial pressure of CO_2 changes. At lower load in coal plants, the CO_2 concentration or partial pressure decreases as less fuel is burned to generate a smaller amount of steam. At the same time, the amount of air blown into the boiler does not decrease in direct proportion to the decrease in fuel flow. This is because a certain volume of gas is needed to flow through the boiler to maintain appropriate steam temperature balance and other criteria necessary to ensure adequate operation of the plant. The result is a more dilute CO_2 stream that still must be captured at 90%. While the referenced GCCSI report may erroneously assume a 90% coal unit capacity factor in its cost models, the report does provide a detailed explanation of why CO_2 capture costs increase with decreasing partial pressure of CO_2. However, the EPA does

not acknowledge that each plant operates in a dynamic environment. The models the EPA uses or references in its technical support document are spreadsheet models assuming constant heat rate, constant CO_2 concentrations, and constant load. The EPA's models fail to reflect the reality of variable coal unit capacity factor operations and are, therefore, inapt tools for assessing the costs or technical viability of CCS in real world conditions. This is a reality of physics, but is neglected by the EPA's cost analysis, which assumes impractical, and misrepresentative static operating conditions not found in real life operation. In doing so, the EPA has not acknowledged real-world operation which will drive up capture costs, but instead cherry picked a number from operation conditions that the EPA has proven is not attainable.

Furthermore, the EPA makes no mention of how the BSER implementation would impact this very valuable grid service of dispatchable synchronous generation which is critical to balance the addition of intermittent inverter-based resources, such as wind and solar, on the grid.

Unfortunately, the EPA is inconsistent in its financial models in terms of baseline assumptions related to coal unit and capture system operations, and does not try to normalize any of the data. Regrettably, where the EPA was consistent in its analysis, it was by erroneously assuming static operating conditions that misrepresent the utilization of the coal fleet in the current electrical grid. These assumptions lead to an underestimation of costs related to CO_2 capture. The EPA should use practical and normalized assumptions and data to understand the actual cost implications of installing CCS on the fleet. Only then will it be possible to determine whether there is appropriate cost justification.

EPA Cost Estimate Flaws in Natural Gas Fired Applications

Unfortunately, the EPA also uses multiple models with varying assumptions in the *Greenhouse Gas Mitigation Measures Carbon Capture and Storage for Combustion Turbines* technical support document, which leads to a muddled mishmash of inaccurate cost assumptions. For example, the document cites the NETL report *Cost and Performance Baseline for Fossil Energy Plants Volume 1: Bituminous Coal and Natural Gas to Electricity* (DOE/NETL - 2023/4320, October 14, 2022),[6] which makes several critical assumptions on pages 33 and 34, indicating that the costs of a greenfield site are a best possible scenario.

The site is said to have rail access, adequate municipal and ground water resources, an elevation of sea level, level topography, relatively low temperature cooling water of 60°F, and Midwest labor rates. This is not adequately representative of the existing fleet or proposed natural gas units that would be subject to these rules.

For example, the generic Midwest location cited in this report is not subject to extreme heat, hurricanes, an arid climate or lack of water, extreme cold, seismic zones three or four, high labor costs or shortages, lack of real estate, geographic constraints, challenging geology, or any other factors that will drive up cost significantly. Any existing or new unit will inevitably be located

[6] *Cost and Performance Baseline for Fossil Energy Plants Volume 1: Bituminous Coal and Natural Gas to Electricity* (DOE/NETL - 2023/4320, October 14, 2022), Accessed 7/7/23, Available at: https://netl.doe.gov/projects/files/CostAndPerformanceBaselineForFossilEnergyPlantsVolume1BituminousCoalAndNaturalGasToElectricity_101422.pdf

above sea level and as high as 6,780 feet. The report may be reasonable for determining the least cost of CCS in a greenfield site, but it is not useful or reasonable to extrapolate those least cost values to the incredibly diverse climates and conditions that vary drastically throughout the United States, particularly for existing natural gas units located in disparate regions throughout the country with fundamentally different baseline conditions.

It does not appear that the EPA seriously considered the cost impacts of actual CCS implementation at real sites beyond mention of several front-end engineering design (FEED) studies. However, when the EPA referenced the FEED studies, it did not acknowledge the significant cost impact associated with implementation of CCS at an actual site.

As an example, the EPA provides its own cost estimates for CCS for new combustion turbines in Figure 7 of the *Greenhouse Gas Mitigation Measures Carbon Capture and Storage for Combustion Turbines* technical support document with the following assumptions: "12-year amortization, 7 percent interest rate, $3.69/MMBtu natural gas, $85/tonne tax credit, 75 percent capacity factor, and $10/tonne TS&M cost."

First, the $85/ton tax credit (which, as noted previously, is an overestimate and not guaranteed) is only valid for 12 years. Any plant that is built or retrofit would be run for considerably longer than 12 years, at which point the tax credit expires. It also assumes that the host unit is able to operate at a capacity factor of 75% – requiring at least a 75% availability rate for the capture unit – in its first year of the capture system operation, which has never before been achieved. As previously discussed, Boundary Dam's capture system achieved 75% availability, which would translate to less than 75% capacity factor, 8 years after commissioning its CCS system. Therefore, the EPA's assumption of a 75% host unit capacity factor in the first year of operation, and still being compliant with the proposed emission limits, is completely unreasonable and invalid. Also, as previously discussed, the cost of TS&M is likely to significantly exceed $10/ton – perhaps by 300% or more at $30/ton– and the EPA completely neglects to show the cost of abatement when the tax credit expires.

Furthermore, the EPA in Figure 9 of the *Greenhouse Gas Mitigation Measures Carbon Capture and Storage for Combustion Turbines* technical support document provides the following assumptions when calculating costs for retrofit CCS NGCC costs: "7 percent interest rate, $3.69/MMBtu natural gas, $10/tonne TS&M costs, $85/tonne tax credit for 12-year amortization, and $45/tonne tax credit for 30-year amortization." It should be noted that currently such a $45/tonne tax credit does not exist. The EPA has no basis whatsoever to assume potential tax incentives of amounts and durations that have not been written into law.

There has not been a single large pilot or commercial demonstration of any CCS technology, including secure geologic storage, at any natural gas-fired plant in North America. Therefore, the EPA cannot claim that any financial, cost, or performance models or assumptions have been validated by any projects in North America. The EPA also cites a number of FEED studies as evidence to why the best system of emissions controls exists. However, the EPA misunderstands or fails to consider the cost information included therein.

For example, the EPA cites the Mustang Station FEED study for a capture system at an existing NGCC unit. The FEED study estimated a cost of CO_2 captured (not including TS&M) of almost $170/ton, assuming a 10% internal rate of return and at the plant's current 52% capacity factor. Even at an 85% capacity factor, which is not achievable, the cost of capture would still come to $85/ton.[7] This example illustrates how site-specific conditions can create significant cost escalation. In the case of Mustang Station, the lack of additional water sources required dry cooling for the CO_2 capture system. This not only created a significant increase in cost, but also shows that the EPA has completely overlooked the water resource requirements of implementing CCUS in their analysis. The EPA must account for these sorts of costs in its cost estimates.

EPA's Misrepresentation of the 45Q Tax Credit

The EPA assumes that the tax credit is immediately applicable to the project, and cuts a flat $85/ton off the cost of captured and stored CO_2. This is a gross misrepresentation of the 45Q tax credit and how the credit is issued, obtained, traded, and monetized in reality. Even with the direct pay provisions passed by Congress, the EPA's methodology is not how the 45Q tax credit functions.

The EPA has assumed that every project can meet all requirements of the enhanced 45Q tax credit, which is not necessarily a valid assumption. In order to qualify for the "enhanced" 45Q tax credit rate outlined in the Inflation Reduction Act, entities must complete a variety of apprenticeship, prevailing wage, and domestic content requirements. While waivers are available, the EPA just assumes that all of the necessary conditions will be met by each project in each jurisdiction. The EPA also does not assume any cost borne by the owner of a project to comply with these significant reporting and compliance requirements.

Further, the assumption that the credit is directly paid and instantaneous shows that the EPA misunderstands (or misrepresents) basic tax law or financial modeling. Even with the direct pay provision, only municipalities and cooperatives would qualify for direct pay from the Treasury for the 12-year credit duration, which is a small percentage of the overall fleet. The remainder of the fleet would require a tax credit posted against federal income tax for 7 of the 12 years of the credit duration. Given that many of these projects will be generating $100 million or more in tax credits annually, it is highly improbable that the project owner or utility owner would be able to directly utilize the tax credits internally, especially for those with multiple units. For example, a relatively small 400 MW coal plant with an 80% capacity factor would generate $255 million in annual tax credits, which would far exceed any income tax generated by the unit.

Instead, the utility will need to transfer some of the tax credits to a tax equity investor who will be able to utilize the tax credits. This assumes that a tax equity investor is willing to invest in the project with technology that is not currently running in the United States and has never operated at the rate, scale, and consistency required under the EPA's proposed rules.

[7] *Piperazine Advanced Stripper Front End Engineering Design*, Available 7/10/2023, Accessed at: https://netl.doe.gov/projects/files/Piperazine%20Advanced%20Stripper%20(PZAS™)Front%20End%20Engineering%20Design%20(FEED).pdf

Additionally, the process for negotiating and agreeing to such a tax equity arrangement could take months, if not years, and would likely need to be finalized before project financing can be secured. This would likewise impact the ability of the project or utility owner to receive the assumed benefits of the tax credit and would delay construction and operation of the capture unit, assuming the tax equity deal could be finalized in the first place. Furthermore, the number of tax equity investors who can utilize $255 million in annual income tax credits will likely be a much smaller number than the number of coal and gas plants potentially impacted by this proposed rule. The EPA completely ignores the difficulty faced by a utility to secure financing and the requisite tax equity investment, which will be critical to raising the necessary capital to build a CO_2 capture system. As a result, there is no possible way that each plant impacted by this rule could possibly secure the necessary financing and tax equity investment required to comply at costs that are even close to what the EPA has suggested.

Plants that can complete this regulatory and financing gauntlet will still face additional transactional costs, which the EPA ignores. Assuming a project can move forward and is able to secure a tax equity investor, the tax credit will be transferred from the project owner to the tax equity investor. When this occurs, there will be a transaction cost, as no tax equity investor will go through the exercise without receiving a return on investment for procuring the tax credits. With a wide range of secure and low- to no-risk investments offering 4.5% to 5.35% rates of return in July 2023 at current interest rates, it is reasonable to assume that a minimum 10% and more realistically a higher transaction cost would be associated with the transfer of the tax credit, thus immediately reducing the credit value from $85 to $76.5 per metric ton to the CCS system owner.

Furthermore, the misleading benefit of the credit by the EPA also neglects the impact of time. Even in years when the CCS system owner may qualify for the direct pay provision, the payment is not immediate. The ton of CO_2 must be verified by either the EPA Subpart RR or ISO 27914 and submitted to the Treasury. Upon approval from the Treasury, a check may be issued on a quarterly basis. As a result, the system has been operating, capital payments are being made, and CCS operational system costs are being incurred for an absolute minimum of 91 days. Therefore, the CCS system owner must continue to pay down the debt associated with the CCS system, while waiting for compensation of the tax credit or direct payment.

The EPA acknowledges in some of its financial modeling that there is a difference between “overnight costs” and “total as spent” costs, and that many activities, like construction, are not instantaneous and result in costs related to interest being accrued over time. However, the EPA neglects this same reality when it comes to receiving the direct payment, which will happen, at most, quarterly. On a 7% annual interest rate, this effectively creates a 1.7% discount quarterly of the revenue from 45Q. Therefore, the best case is for a direct payment equivalent to $83.55 per metric ton. But, even that would only apply to a small fraction of the impacted generating units owned by municipalities and cooperatives. The majority of units are owned by investor-owned utilities which would not qualify for the full 12-year direct pay provision.

The fact that the EPA does not apply this same basic financial modeling principle to the tax credit as was applied to construction costs of the CCS system indicates that the EPA is fundamentally contradictory in its modeling assumptions. Furthermore, while 1.7% may not seem significant, it

is part of a broader pattern of compounding assumptions that lead to a very significant underestimation of compliance costs that will be directly borne by the electricity consumer.

The EPA needs to fundamentally change its financial modeling to account for the very significant hurdles, as well as costs associated with financing, building, and operating a CCS installation.

Conclusions

The EPA has not sufficiently modeled the cost of CCS implementation, nor has the EPA sufficiently modeled the impacts of adding CCS to the existing fleet in terms of grid impacts, cycling capabilities to meet the needs of an increasing renewable energy penetration grid, water use and impacts, and technological readiness.

The EPA should perform an adequate analysis to determine how the technology required will impact the operation of the grid, and what it will cost in a variety of regions throughout the country, all of which will be significantly impacted by this regulation.

Instead, the EPA has used fundamentally flawed models which do not use consistent baseline assumptions. Their assumptions use conflicting costs for CO_2 transportation, storage, and monitoring. The assumptions use capacity factors that are not reflected in the actual capacity factor data from the EIA, extrapolate the least cost construction environments to the entire United States without any acknowledgement of how location substantially impacts costs, completely misrepresent the impact of the 45Q tax credit in financial modeling, and provide conflicting examples of BSER projects, which would likely not even comply with the proposed rule as justification for the rule.

About the Authors

Dr. William Morris, Carbon Management Strategies, LLC

Dr. William Morris completed his Ph.D. and M.S. in chemical engineering at the University of Utah, examining the effect of pollutants such as NO_X, SO_X, and particulate matter on aerosol formation in air and oxy-fired combustion for CO_2 capture. He also holds a coordinate A.B. in Physics and Environmental Studies, with a minor in History from Bowdoin College. He is currently president and technical director of Carbon Management Strategies LLC. He is also contracted by the Wyoming Energy Authority (WEA) as Program Director to provide engineering and business development support services for CO_2 management technologies testing at the Wyoming Integrated Test Center (ITC). The ITC facility is a public/private venture between Basin Electric Power Cooperative, Tri-State G&T, the National Rural Electric Cooperative Association, Black Hills Power, and the state of Wyoming through the Wyoming Infrastructure Authority. The research facility can provide up to 23 MW equivalent of flue gas for large pilot post combustion CO_2 capture testing, as well as 6 small 0.4 MWe test bays which have hosted the NRG COSIA Carbon XPRIZE CO2 utilization competition as well as a post combustion capture system from TDA Research. Additional projects in the procurement phase are Kawasaki Heavy Industries solid adsorbent technology, Membrane Technology and

Research's 180 tonne per day membrane CO_2 capture facility, and another 24 ton per day membrane capture system led by Gas Technology Institute and the Ohio State University.

As an employee of ADA Environmental Solutions, Dr. Morris worked in the areas of mercury emissions control, CO_2 capture, NO_X control, and is the listed inventor on 3 issued NO_X, mercury, and CO_2 emissions control patents, as well as other patents pending. He was also a contributing author to the oxy-fuel combustion section of the National Coal Council's report, *Fossil Forward,* in 2015 for then Department of Energy Secretary of Energy, Ernest Moniz, providing an update on CO_2 capture technologies. In addition, he was the CO_2 use chapter co-lead with Professor Alissa Park of Columbia University for the National Petroleum Council's report, *Meeting the Dual Challenge - A Roadmap to At-Scale Deployment of Carbon Capture, Use, and Storage*. He has conducted basic research, small pilot research, and commercial scale demonstrations and trials of various mercury, NO_X, and emissions control technologies with both private industry and universities. Commercialization success included developing a novel coal treatment process to qualify for the IRS section 45 refined coal tax credit, which produced approximately $1.8 billion in tax credits. Previous partners have included University of Utah, University of California Berkeley, Texas A&M University, Lehigh University, Southern Company, Aspen Aerogels, The University of Akron, the Electric Power Research Institute, the National Energy Technology Laboratory, the U.S. Department of Energy, and other private industry companies. In addition, he has been a peer reviewer for the journals of American Chemical Society as well as Elsevier Publishing.

Mr. John Weeda, Quail Hollow, LLC

John Weeda is a professional engineer (retired) with a long history of startup, operation, and maintenance of large generating plants and ethanol production facilities. Over the years, he served in roles of engineer, engineering management, plant management, operations director, and interim CEO and board member. The facilities that Mr. Weeda worked in and was responsible for included nuclear fuel, lignite, sub bituminous, and combined heat and power. The organizations that he worked with pioneered and patented several new technologies. The largest of these is a coal drying technology that has dried more lignite than any other technology in the world. The ethanol facilities that Mr. Weeda was involved in developing pioneered the use of waste heat in the ethanol production process and are a major supply of low carbon ethanol to the low carbon fuels market.

During his career, Mr. Weeda has worked closely with other organizations, such as the Electric Power Research Institute, to research and adopt technology to the power industry that brought improved efficiency and environmental performance from demonstration to commercialization. The facilities that he was responsible for recognized that success in operation was driven by success in the marketplace. This applied to both the products that were offered and the price of the products competing against others in the market. A good example of that is taking the fly ash from being a waste product to being a product that is specified by name in the civil specifications for many civil projects in the region.

In recent years, Mr. Weeda applied that background in generation and markets to the electric grid. In the North Dakota Transmission Authority role, he emphasized the need for North Dakota

to get their product to market with adequate transmission, emphasizing the clean energy role that North Dakota plays in that market and to be a leading state in having “all of the above” energy resources working together for the benefit of the country.

Mr. Weeda was an active cooperative member of NRECA for many years and, now as a consultant with NRECA, John has helped bring information to the membership that will keep their generation resources viable in the changing energy environment they are facing.

Attachment F

Analysis of the EPA's Proposed Power Plant Greenhouse Gas Emissions Rule Impact on Generation Resource Adequacy and the Need for Transmission Alternatives

Regarding: EPA's Proposal 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"
(Docket EPA-HQ-OAR-2023-0072)

Prepared for the National Rural Electric Cooperative Association By:
Mr. John Weeda, Quail Hollow, LLC

August 3, 2023

Executive Summary

Attempted compliance with the EPA's proposed greenhouse gas regulations for new and existing power plants will have a serious impact on the reliability of the electricity grid based on testimony from the Federal Energy Regulatory Commission (FERC), assessment of reliability by the North American Electric Reliability Corporation (NERC), and regional assessment by the Center for the American Experiment.

Shutting down existing fossil fuel resources, driven by compliance requirements of the EPA's proposed rule, would result in a massive need for renewable energy. This generation is geographically distributed and weather dependent, requiring the need for massive investment in transmission infrastructure and affecting the economics associated with investing in alternative technologies in an effort to keep the electric grid functional and reliable. These investments are expected to amount to trillions of dollars per region of the country and involve huge construction, putting unprecedented demand on labor and materials.

Assessments of Generation Resource Impact

The EPA's proposed regulations would set strict carbon dioxide (CO_2) limitations for gas- and coal-fired units based on installation of carbon capture and storage (CCS), fuel switching to natural gas or hydrogen, and/or committing to major limitations as follows:

- Compliance options for existing coal-fired units:
  - Commit to retire prior to January 1, 2032 – Maintain current level of performance/emission rate; no other compliance action required.
  - Commit to retire prior to January 1, 2035 – Maintain current level of performance/emission rate; limit annual capacity factor to 20% maximum beginning January 1, 2030.
  - Commit to retire prior to January 1, 2040 – Reduce emission rate by 16% beginning January 1, 2030, based on co-firing 40% natural gas.
  - No retirement – Reduce emission rate by 88.4% beginning January 1, 2030, based on 90% removal with CCS.

- Compliance options for existing gas-fired units (applies to units of 300 MW or larger with an annual capacity factor of 50% or more):
  - Two options for compliance:
    - Clean hydrogen: 30% co-firing by January 1, 2032, 96% by 2038, or
    - CCS: standard assumes 90% capture rate by January 1, 2035.

The technologies for CCS are in their infancy of commercialization and should not be considered the Best System of Emissions Reductions (BSER) at this time. In any event, even if CCS were demonstrated and generally achievable, it is next to impossible for any coal-fired unit that had

not already started the process of design or construction of CCS, even before EPA proposed the rule, to construct CCS by January 1, 2030. So the CCS option, at least for coal-fired power plants, is illusory. It is also largely illusory for gas-fired combustion turbines. Fuel switching to natural gas is not practical for many generators due to lack of access to natural gas and other technical difficulties associated with each unit design. For example, with respect to the latter, adding or increasing flue gas recirculation will be needed and adding hundreds of horsepower. Heat transfer in the boiler surfaces would be affected, requiring modification or addition of heat transfer surface. The exit gas temperature from the boiler would typically increase, causing shortened life of the equipment at the back of the boiler and downstream. The heat rate measure of unit efficiency is typically negatively affected. A detailed engineering analysis would have to be completed by each generation owner to determine the feasibility of a gas conversion. In summary, these changes that affect the efficiency of the generation are contrary to progress that the industry made for many years of increasing efficiency to get more electricity for the customer at a lower cost. These challenges are discussed in the Babcock Power Services publication "Leveraging Natural Gas: Technical Considerations for the Conversion of Existing Coal-Fired Boilers."[1]

The alternative use of hydrogen as a fuel for combustion turbines is not practical due to current lack of fuel availability, high cost, and the need for long-term demonstration of the technology in existing generators. Prior to any mandated new buildout of hydrogen generators, the equipment manufacturers must demonstrate reliability and drive down the cost of the equipment. For further details on this topic, please see related comments on hydrogen.[2]

Reliability and Resource Adequacy Concerns

The Federal Energy Regulatory Commission (FERC) has raised the alarm to Congress in recent testimony about the continued loss of dispatchable generation without sufficient and adequate replacement: "There is a looming reliability crisis in our electricity markets," FERC Commissioner James Danly said. "The United States is heading for a very catastrophic situation in terms of reliability," FERC Commissioner Mark Christie said. FERC Acting Chairman Willie Phillips said, "We face unprecedented challenges to the reliability of our nation's electric system." The full recording of the FERC testimony to Congress is available online.[3]

At another Congressional hearing, North American Electric Reliability Corporation (NERC) CEO, Jim Robb, was asked whether renewables and transmission could sufficiently replace generation assets forced to retire early as a result of EPA regulations. Robb stated flatly "No. Not in the timeframe we're looking at." PJM Interconnection CEO, Manu Asthana, similarly stated

[1] Leveraging Natural Gas: Technical Considerations for the Conversion of Existing Coal-Fired Boilers.[1] Jason C. Lee, P.E. and Michael Coyle, Babcock Power Services, Inc. Presented at ASME Power Conference July 2014, Baltimore, MD, https://www.babcockpower.com/wp-content/uploads/2018/01/leveraging-natural-gas-technical-considerations-for-the-conversion-of-existing-coal-fired-boilers.pdf

[2] *Analysis of Hydrogen in Combustion Turbine Electric Generating Units. Regarding: EPA's Proposal 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" (Docket EPA-HQ-OAR-2023-0072)*, Doug Campbell, August 3, 2023

[3] https://www.energy.senate.gov/hearings/2023/5/full-committee-hearing-to-conduct-oversight-of-ferc

that "we need to hang on to resources we have today that work, until their replacement is here," and that the EPA's proposed greenhouse gas regulations for power plants "will continue to push this generation off the grid." The full recording of this testimony to Congress is available online.[4]

NERC prepares reliability reports each summer and winter season. The last three reports have cautioned that large areas of the country are at risk regarding reliable electric supply. Recently, winter storms Uri and Elliot have shown that the reliability and resilience of the electric grid with the current generation fleet are not adequate to keep electric supply to customers in adverse conditions. Furthermore, this current fleet is much less weather dependent than the proposed decarbonized fleet. A detailed review of NERC assessments is available online.[5]

On a regional level, regional transmission organizations (RTOs) and independent system operators (ISOs) are increasingly calling attention to the rapid retirement of baseload, thermal resources as a result of government policies, private sector actions, and economics. Forward-looking studies of the resource adequacy of the electric grid commissioned by the North Dakota Transmission Authority have examined addition and retirement of resources in both the Midcontinent Independent System Operator (MISO) and the Southwest Power Pool (SPP) regions of the country, with a projection of which resources are likely to shut down as a result of the cost of compliance with the EPA's coal combustion residuals regulations and Ozone Transport Rule.[6,7] These studies[8] show that by 2026, neither MISO nor SPP will have adequate dispatchable resources to meet peak load demand. In other words, the grid will require dispatchable and reliable resources and favorable weather conditions to operate weather-dependent resources to even meet the peak demand. Before the end of the decade, these weather-dependent resources may be required to provide over one-third of the generation to meet those peak demand times in the SPP region. This concern is clearly a contributing factor to FERC and NERC raising the alarm that our reliable electric grid is at risk.

If utilities are required to install carbon capture on the existing baseload dispatchable fleet, **the capacity of the fleet will be reduced by 25% to 30% parasitic load**. This reduces the net plant output by that amount and is a huge increase in net heat rate, which means the efficiency is much lower. In this resource constrained grid, the resources to power the carbon capture systems are not available. The carbon capture system needs to run full-time when the plant is operating, which is not possible with renewable resources that are dependent on favorable weather conditions. The 18% parasitic load referenced by the EPA on page 8 of the Resource Adequacy Technical Support Document[9] is not accurate. Front-end engineering design (FEED) studies that

[4] https://www.energy.senate.gov/hearings/2023/6/full-committee-hearing-to-examine-the-reliability-and-resiliency-of-electric-services-in-the-u-s-in-light-of-recent-reliability-assessments-and-alerts

[5] https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_LTRA_2022.pdf
https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_WRA_2022.pdf
https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_SRA_2023.pd

[6] Forecasting Resource Adequacy in MISO Through 2035 May 23, 2023. Mike Nasi, Brent Bennett, Isaac Orr, and Mitch Rolling

[7] Forecasting Resource Adequacy in Southwest Power Pool Through 2035 May 23, 2023. Mike Nasi, Brent Bennett, Isaac Orr, and Mitch Rolling

[8] North Dakota Transmission Authority | North Dakota Industrial Commission. On the site, select Power Forecast Reports and then the SPP or MISO document.

[9] http://www.epa.gov/system/files/documents/2023-05/Resource%20Adequacy%20Analysis%20TSD.pdf

are in progress and complete for Minnkota Power's Project Tundra and for Rainbow Energy's Coal Creek Station conclude that an accurate range for parasitic load is 25% to 30%.

The Electric Power Research Institute (EPRI) plans to submit testimony that the status of development of this technology is years from being commercially proven and should not be required.

Many regions of the country are projected to be increasingly dependent on favorable weather conditions to support wind and solar generation to meet peak demand. MISO, which is likely to be the location of the first carbon capture systems on large generating facilities, is already identified as being at risk in the NERC reliability assessments reference above. Unless additional, firm capacity offsets the parasitic load of the carbon capture system, these regions and the RTOs and ISOs responsible for them would be further strained by that additional loss of dispatchable load.

Transmission Additions as a Possible Solution

For additional wind and solar generation to replace lost capacity from coal and natural gas units required to close under this proposal, or to offset the parasitic load of carbon capture systems (putting aside the immaturity of that technology and the unrealistic time horizon for constructing them under the proposed rule), significant amounts of new transmission capacity will be required, as these renewable resources are not often located in the area of current generating units. However, the EPA assumptions of the options that utilities have for additional generation and the transmission capacity to support them are overly simplified.

For example, the EPA's discussion related to transmission on pages 3-4 of the Resource Adequacy Technical Support Document states that their Integrated Planning Model (IPM) "addresses reliable delivery of generation resources between the 78 IPM regions, based on current and planned transmission capacity, by setting limits to the ability to transfer power between regions using the bulk power transmission system, as well as the ability to endogenously expand these links based on relative economics. Within each model region, IPM assumes that adequate within-region transmission capacity exists or will be built to deliver any resources located in, or transferred to, the region." [10]

Perhaps the most complete study of transmission needs to achieve high penetration of renewable generation to replace fossil generation as a result of retirements due to regulations and other factors is the U.S. Department of Energy's (DOE) National Transmission Planning Study.[11] The final report is scheduled to be released later in 2023, but the review draft provides preliminary results that will likely be sustained in the final version. DOE is working with national laboratories and stakeholders to "identify viable future grid realization pathways to a large-scale transmission system buildout that would accomplish clean energy goals," including the

[10] Environmental Protection Agency. *Resource Adequacy Analysis Technical Support Document*. May 23, 2023. p.3-4. Available at: https://www.epa.gov/system/files/documents/2023-05/Resource%20Adequacy%20Analysis%20TSD.pdf

[11] National Transmission Planning Study (draft), NTPStudy@hq.doe.gov

Administration's goal to achieve 100% carbon free electricity nationally by 2035.[12] The study focused on interregional transmission, in order to facilitate a national grid that utilizes carbon neutral sources more efficiently.

The graphics within the report provide a clear picture of the amount of transmission build that is needed to reach those decarbonization goals. A heavy concentration of new transmission capacity is needed, especially in the more populous central parts of the country. The experience of the utility sector in recent years shows that building transmission is a challenging multi-year process, and in the more populated areas, it can be nearly impossible. Ten years or longer is often required from concept to in-service, including for transmission lines within an RTO region, or even within the much smaller regions as defined by EPA's IPM model. In fact, FERC's current proposal to reform regional transmission planning envisions a 20-year long-term planning scenario.[13]

Interregional transmission, between reliability regions, states, and even the EPA's small IPM regions, adds another level of complication that experience has shown further extends these timelines. Since transmission decisions are mostly made at the state level, even developing the processes to build interregional transmission efficiently will take time. In other words, the transmission buildout is a decades-long effort once a decision has been made – and the requirements set out in the EPA's proposed rule do not afford this time. Other details on proposed timelines for CCS infrastructure are available in related comments submitted by NRECA.[14]

A recent example is the MISO Multi-Value Project (MVP), a portfolio of 17 projects in the MISO region with an estimated cost of over $5 billion. After roughly six years of discussions, evaluations, planning, and cost approvals that began in 2005, MISO officially approved the slate of MVP projects in December 2011.[15] More than five years later, 13 of the 17 MVP projects were still not in service, including many that are wholly within the EPA's IPM more limited "model regions," that are assumed to have or will have sufficient transmission capacity.[16] Four were still incomplete in the third quarter of 2019, nearly eight years after MISO approval.[17] And the highest value project of the 17, the Cardinal-Hickory Creek transmission project, is still not in service, more than 12 years after MISO approval, due to drawn out permitting processes and litigation.

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[12] Department of Energy. *Building a Better Grid Initiative To Upgrade and Expand the Nation's Electric Transmission Grid To Support Resilience, Reliability, and Decarbonization.* January 19, 2022. 87 FR 2769. Page 2771. Available at: https://www.govinfo.gov/content/pkg/FR-2022-01-19/pdf/2022-00883.pdf

[13] Federal Energy Regulatory Commission. *Building for the Future Through Electric Regional Transmission Planning and Cost Allocation and Generator Interconnection, Notice of Proposed Rulemaking*. RM21-17, May 4, 2022. Available at https://www.federalregister.gov/documents/2022/05/04/2022-08973/building-for-the-future-through-electric-regional-transmission-planning-and-cost-allocation-and

[14] *Analysis Of EPA's Proposed Construction Timeframes for CCS Projects. Regarding: EPA's Proposal 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" (Docket EPA-HQ-OAR-2023-0072)*. Daniel Walsh, August 3, 2023

[15] AESL Consulting, https://www.aeslconsulting.com/wp-content/uploads/2021/11/MISO-MVP-History.pdf

[16] MTEP17 report, https://cdn.misoenergy.org/MTEP17%20MVP%20Triennial%20Review%20Report117065.pdf

[17] MTEP19, https://cdn.misoenergy.org/2019%20MVP%20Limited%20Review%20Report443829.pdf

Another example is the TransWest Express Transmission project,[18] a high-voltage, interregional transmission line crossing three states in the Mountain West. According to TransWest Express, LLC, this project was initiated in 2005 by Arizona Public Service, with the permitting process beginning in 2007 with the filing of a right-of-way application. It was not until more than 15 years later that final federal approval for the construction of this transmission line was received. TransWest estimates that construction of the transmission line will take about three years, meaning that the earliest it would be in-service would be more than 20 years after it was first initiated.

Cost is another key consideration. The DOE's National Transmission Planning Study estimates the cost of the needed transmission and generation to be at $120 billion to $170 billion per year from now through 2050 to meet the decarbonization goals, including a decarbonized electric grid by 2035, as listed above. For MISO and the PJM Interconnection, this is estimated at over a trillion dollars for each of those two regions. Other RTOs and ISOs will also require hundreds of billions of dollars.[19] This level of expenditure is unprecedented and likely not feasible.

Additional consideration must also be given to factors that could delay the construction of transmission projects. The recent strains on the supply chain resulting from COVID-19 are continuing to impact construction schedules for transmission. Transformers of all sizes are difficult to obtain, and domestic production is very limited. Sources of materials supply for transformer steel, copper, and other parts are often in areas of the world that may not be able to reliably serve the needs of the U.S. utility sector. Finally, it cannot be presumed that generator interconnections that will utilize such additional transmission capacity will occur in the timelines that EPA assumes.

Conclusion

The EPA's proposed greenhouse gas regulations for new and existing power plants sets expectations for CO_2 reductions that are not achievable considering the present state of technology, the adverse impacts on electric grid reliability, and the timelines and massive investment required for additional electric transmission infrastructure.

About the Author

Mr. John Weeda, Quail Hollow, LLC

John Weeda is a professional engineer (retired) with a long history of startup, operation, and maintenance of large generating plants and ethanol production facilities. Over the years, he served in roles of engineer, engineering management, plant management, operations director, and interim CEO and board member. The facilities that Mr. Weeda worked in and was responsible for

[18] https://www.transwestexpress.net/about/history.shtml
https://www.transwestexpress.net/about/timeline.shtml

[19] National Transmission Planning Study (draft), NTPStudy@hq.doe.gov

included nuclear fuel, lignite, sub bituminous, and combined heat and power. The organizations that he worked with pioneered and patented several new technologies. The largest of these is a coal drying technology that has dried more lignite than any other technology in the world. The ethanol facilities that Mr. Weeda was involved in developing pioneered the use of waste heat in the ethanol production process and are a major supply of low carbon ethanol to the low carbon fuels market.

During his career, Mr. Weeda has worked closely with other organizations, such as the Electric Power Research Institute, to research and adopt technology to the power industry that brought improved efficiency and environmental performance from demonstration to commercialization. The facilities that he was responsible for recognized that success in operation was driven by success in the marketplace. This applied to both the products that were offered and the price of the products competing against others in the market. A good example of that is taking the fly ash from being a waste product to being a product that is specified by name in the civil specifications for many civil projects in the region.

In recent years, Mr. Weeda applied that background in generation and markets to the electric grid. In the North Dakota Transmission Authority role, he emphasized the need for North Dakota to get their product to market with adequate transmission, emphasizing the clean energy role that North Dakota plays in that market and to be a leading state in having “all of the above” energy resources working together for the benefit of the country.

Mr. Weeda was an active cooperative member of NRECA for many years and, now as a consultant with NRECA, John has helped bring information to the membership that will keep their generation resources viable in the changing energy environment they are facing.

Attachment G

Analysis Of EPA's Proposed Construction Timeframes for CCS Projects

Regarding: EPA's Proposal 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"
(Docket EPA-HQ-OAR-2023-0072)

Prepared by National Rural Electric Cooperative Association's
Mr. Daniel Walsh, Senior Power Supply & Generation Director

August 3, 2023

Executive Summary

After conducting interviews with staff at several Tier 1 Engineering, Procurement and Construction (EPC) companies in the power industry, it is the conclusion of the author that the proposed timeframes for carbon capture and storage (CCS) established by the U.S. Environmental Protection Agency (EPA) for its proposed greenhouse gas (GHG) emissions standards are significantly flawed and, at best, aspirational. Key assumptions regarding site conditions, access to CO_2 pipelines, local support for a project, and times for permit reviews have not been adequately considered, resulting in an unrealistic timeframe by the EPA. Based on discussions with EPC firms, the existing site conditions along with distance and access to CO_2 storage are critical in determining an appropriate overall project schedule.

Note that the time limits discussed in the narrative below are similar for both a natural gas combined cycle and a coal steam electric facility. While there are unique characteristics to all fossil energy sites, these types of differences are minor in terms of overall project schedule impact.

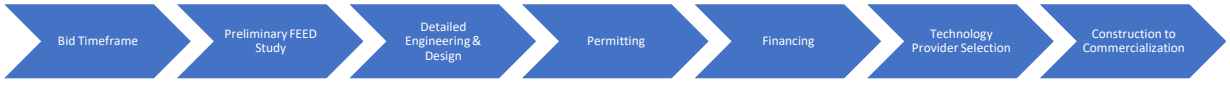
The Tier 1 EPC firms interviewed included Black & Veatch, AECOM, Burns & McDonnell, Kiewit, and Fluor.

In summary, several key assumptions have not been adequately addressed by the EPA and ignored in its review. The result is an unrealistic timeline that cannot be met by the generation industry.

Basis and Analysis

The EPA states that "Deployment of [carbon capture and storage] CCS technology involves a project schedule that can be completed in roughly five years" citing the completion of multiple phases in tandem.[1] This statement is flawed, for the following reasons.

The process from plan inception to commercialization is composed of several key phases, all of which require considerable time in order to successfully accomplish the necessary requirements.



[1] Environmental Protection Agency. *Greenhouse Gas Mitigation Measures for Steam Generating Units Technical Support Document*. May 23, 2023. p. 36.

Bid Period:

Most companies typically require obtaining bids to satisfy procurement rules for a capital-intensive project. The time to bid, review and subsequently engage in a contract for an engineering firm is generally 6-12 months.

Preliminary FEED Study:

The amount of time to perform a front-end engineering design (FEED) study can easily exceed 12 months. In fact, most respondents indicated an 18- to 24-month time with the median at 20 months from the issuance of a purchase order. This amount depends on the complexity and size of the undertaking. In this evaluation comparison, 12 months has been selected to complete the FEED study.

A FEED study precedes a complete engineering evaluation and detailed design specification. This process takes an additional 12-24 months from the date of the purchase order. Following the FEED, the site owner must proceed with the detailed project engineering and work scope details. In this evaluation, 18 months has been used for the detailed engineering and design portion of the project.

Permitting & Financing:

As part of the complex project, the generation owner must obtain state and utility governing board approval, start permitting, and obtain financing to proceed. The financing will be contingent on receipt of Class VI permits for sequestration, selection of an EPC firm and technology provider, and receipt of all required permits, easements, land rights, etc. In addition, the financing usually requires performance guarantees from the construction firm and technology provider. Since the industry is lacking existing facilities which have demonstrated capture percentages at the EPA proposed required amount, the financing will be extremely challenging.

These steps will take between 24 and 48 months. Typically, financial institutions require all permits in hand and engineering to be at least 75% complete to reduce concerns about cost and schedule overruns in the project. The inability to receive all permits in a timely manner will negatively impact financing and construction cost and schedule.

The EPA timeline provides 52 weeks for permitting of carbon capture equipment and 104 weeks for permitting of the necessary infrastructure. This estimate provides little leeway for permitting delays, such as local opposition, which is a typical risk for any construction project, as well as opposition from national groups against these types of projects, which is to be expected for CCS projects. No additional time is provided by the EPA to satisfy this contingency. Given the current lengthy time for receiving permits, it is obvious that the EPA proposed schedule for permitting is severely understated.

With known requirements for parasitic load for capture technologies, a CCS project site owner will have to add generation to serve its load obligations, or alternatively add generation to run the CCS project. This will require more permitting and may trigger a Clean Air Act New Source

Review (NSR) requirement, causing further delays. The EPA has failed to provide a schedule time for the NSR process, which would add 24-36 months of environmental reviews and equipment procurement for new generation units, boilers, and related equipment.

Technology Provider Selection:

It is apparent that this technology has not been adequately demonstrated to achieve the levels or carbon capture amounts and sequestration that EPA proposes. Even setting aside those technical and feasibility barriers, the process to select a technology provider itself takes significant time. In our discussions with several capture technology providers, it was noted that the current backlog to start capture EPC is 12-18 months, further extending the required time. While part of this step would be performed in parallel with obtaining financing, many technology providers will require an initial significant multimillion dollar down payment, typically 20% of the overall supplied equipment cost, to begin work. This makes the timing of the start of work by the technology provider contingent on the timing of successfully obtaining financing.

The technology providers interviewed included Shell CANSOLV, MHI, Fluor, ION/Koch, Honeywell, BASF, Linde, Air Liquide, and Carbon Clean. The firms interviewed stated that the time for construction of the transport pipelines and sequestration sites will exceed the amount of time the EPA has stated for an entire project. The time to construct a facility, perform startup and acceptance testing, and start commercial operation is an additional 60-72 months.

Total Actual Timeline:

Based on the information and research obtained, an accurate time for the construction of a project is more **in the range of 10-12 years after inception**. This is evidenced by the proposed CCS sites that are currently being evaluated in the U.S., like Project Tundra by Minnkota Power Cooperative.

Potential for Variables to Extend the Timeline

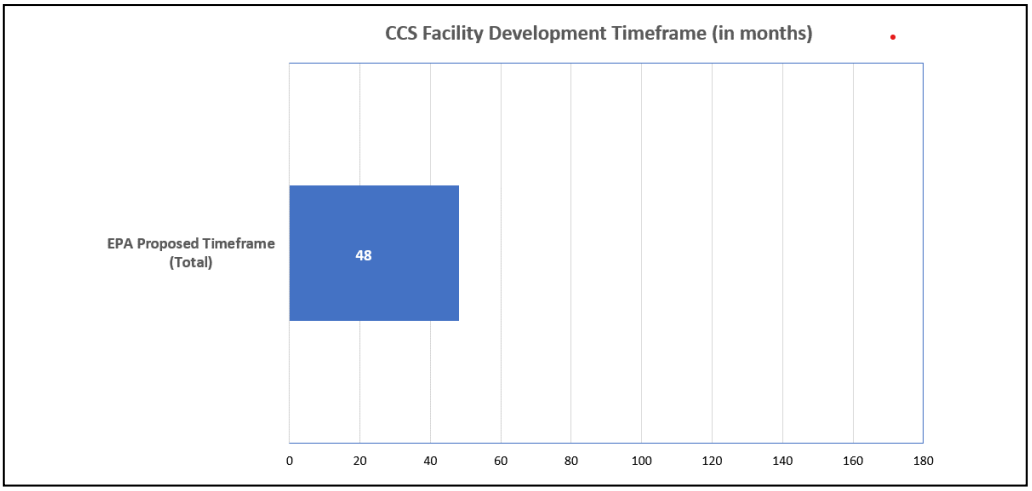
The EPA has failed to address the resource adequacy challenges that will occur when fossil generation sites accept a 25%-30% parasitic load loss to run an associated CCS site. Alternatively, if the generation owner selects to add onsite generation to run the CCS plant, then NSR and additional air permitting requirements that are federal, state, and local based may add an additional 24-36 months prior to commencing construction.

The EPA is currently “targeting” 24 months for permit approvals, following a completeness determination; however, this assumes no deficiencies. This timing is impossible, given inadequate agency resources for permit reviews, an overwhelming reluctance by the agency to support the continued use of fossil generation, and likely intense opposition to permits associated with CCS. Individual EPA regions continue to have limited capacity and lack core expertise to effectively review permit applications in support of a construction time limit required to meet the EPA proposed regulations.

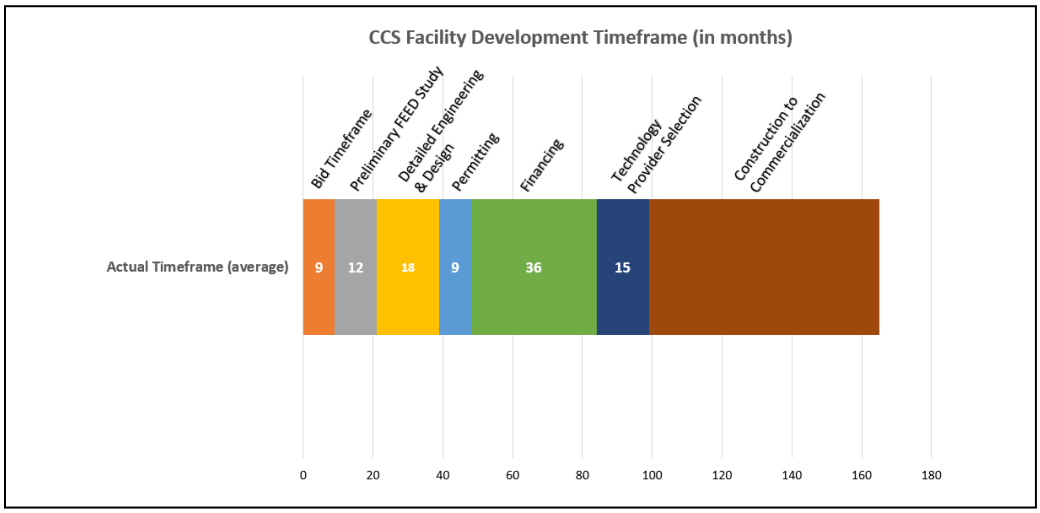
There are also many variables that can influence the exact scope and schedule for acquiring a Class VI underground injection well permit, adding to the already lengthy schedule for design and construction of the upstream carbon capture system. The Class VI well design, permitting and construction process is often longer than that of the carbon capture system. This changes the critical path of a project and pushes commercial operation dates to after the required EPA compliance dates.

EPA Proposed Timeline vs. Actual Timeline

Currently, the EPA believes that the time and schedule for the engineering, construction, and commercial operation of a fully-integrated CCS site can be done in approximately **48 months.**



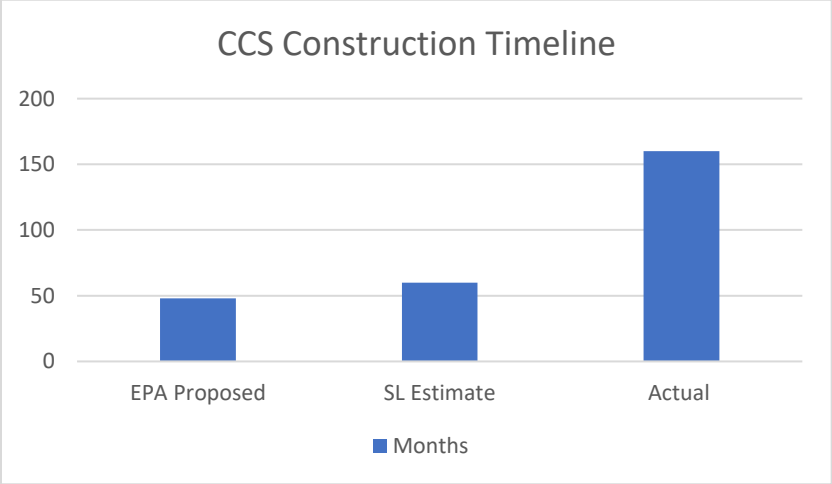
The minimum time for developing and constructing necessary CCS infrastructure, including capture facility, transport pipelines and Class VI well permitting and storage, looks more like **120 to 160 months**, as shown here.



Conclusions

The EPA has not sufficiently considered the relevant factors affecting carbon capture development and is using incorrect assumptions in determining the times required to meet the proposed compliance dates. The assumptions the EPA makes do not adequately address the times required for carbon capture, transportation, or sequestration into an approved permitted site.

The EPA used a high-level Sargent & Lundy (S&L) construction schedule, which showed several key assumptions regarding permits, land rights, water allocation, and sequestration near the CCS project. This S&L schedule clearly stated that the **best-case, high-level schedule would allow construction completion in approximately 60 months and require even more time for these critical assumptions currently absent from the analysis**. Without justification based in facts about the plant development process, the EPA arbitrarily shortened the S&L schedule, leaving an unrealistic and impossible requirement in the EPA proposed rule.



The EPA provides no engineering justification, evaluations, or facts to support a contraction in schedule, other than the belief that federal funding through stimulus and tax credits would somehow reduce the schedule.

It is a flawed assumption that funding from the Inflation Reduction Act will somehow create an environment for streamlined construction of these massive engineering projects. There are many other fundamental factors required for building the suggested large-scale facilities that are simply not in place nor feasible within the timeframe the EPA proposes. This clearly demonstrates the EPA's lack of knowledge and recognition for all the essential steps needed to construct, startup and drive a project to commercial operation.

Additionally, the required infrastructure to support carbon capture from fossil generation is not adequately detailed by the EPA, nor considered correctly. It is unrealistic to assume all generation facilities will obtain or immediately have access to sequestration sites and pipelines that are not in existence as of the date of the EPA proposed rule. Current day infrastructure

simply cannot support the proposed magnitude and time of the required new technology. The EPA's proposed rule uses unrealistic assumptions within its own analysis and relies on FEED studies as examples for why a technology, which has not been built at the scale required, should be considered the best system of emissions reduction.

In summary, the EPA's proposed guidelines are based on insufficient analysis and flawed assumptions that result in a timeline that is not realistic, do not recognize the many essential steps to plant development, and will subject the industry to impossible requirements. Put simply, it is highly unlikely – indeed impossible – for any coal-fired power plant that has not already started the process of designing and constructing a CCS system even before the EPA proposed rule was published, to install CCS by 2030. It is highly unlikely for an existing combustion turbine subject to the EPA proposed rule to install CCS by January 1, 2035.

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About the Author

Mr. Daniel Walsh, NRECA Senior Power Supply & Generation Director

Daniel Walsh is the Senior Director for Generation Research and Development at the National Rural Electric Cooperative Association (NRECA), which represents the interests of over 1,000 not-for-profit electric cooperatives in the United States. In this role, he leads the Generation team overseeing a broad research portfolio including carbon capture use and storage, nuclear, existing

fossil fleet, and advanced power cycles. Under his leadership, the Generation team provides technical expertise, technology assessments, and industry connections to assist NRECA members in meeting the future energy generation challenges.

Mr. Walsh joined NRECA in 2014 and brings over 35 years of experience in the energy sector. Prior to his work at NRECA, Dan held a variety of roles working in gas, steam turbine and generator engineering groups, and as manager of several combined cycle and coal fired sites.

Over his career Mr. Walsh demonstrated in-depth technical, operational knowledge and effective leadership as he advanced from roles of Plant Manager to Senior Vice President. He managed ten power generation sites, where he had responsibilities for profit and loss, environmental, health and safety, operations and maintenance, engineering and construction, and personnel management for more than 1,000 staff.

Mr. Walsh holds a bachelor's degree in mechanical engineering from the University of Connecticut. He has several external leadership roles on advisory boards for EPRI Generation, NuScale Small Module Reactors, ESIG, CEATI and serves on the steering committee for the Carbon Utilization Research Council. Prior to his energy industry career, Dan was in the U.S. Navy where he served onboard a ballistic missile submarine for five deployments. He currently resides in Florida and meets with NRECA electric cooperative members around the U.S.

Attachment H

Analysis of the National Energy Technology Laboratory Cost Estimation Guidelines and Comparison with Alternate Estimate from the Energy Information Administration, Sargent & Lundy

Regarding: EPA's Proposal 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"
(Docket EPA-HQ-OAR-2023-0072)

Prepared for the National Rural Electric Cooperative Association By:
Mr. Doug Campbell, FTB Energy Solutions, Inc.

August 3, 2023

Introduction

This paper provides commentary on the Environmental Protection Agency's (EPA's) proposed rule "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." The proposed rule would require some fossil fuel-fired stationary combustion turbine electric generating units (EGUs) to use emission control measures that are based on highly efficient generating practices, hydrogen co-firing, and carbon capture and storage.[1]

In reviewing the EPA documents for this proposed rule, it is evident that they are dependent on cost projections provided by the National Energy Technology Laboratory (NETL). The EPA cites NETL's 2022 "Cost and Performance Baseline for Fossil Energy Plants Volume 1: Bituminous Coal and Natural Gas to Electricity"[2] in its discussion of carbon capture for coal-fired steam EGUs and natural gas combustion turbines as being "adequately demonstrated." Regarding capture costs at existing coal-fired units, the EPA states that it has "relied heavily" on NETL information, particularly that 2022 Cost and Performance Baseline.

NETL's cost estimates are developed utilizing its Quality Guidelines for Energy System Studies (QGESS) [3] methodology and reports, notably QGESS for Carbon Dioxide Transport and Storage Costs (2019). [4] NETL estimates work very well when used to compare one technology to another. These quality guidelines are published and publicly available. As is explained in the following pages, these estimates are not complete enough to be presented as full project costs. The EPA needs to consider a more inclusive estimate, such as that presented by the EIA in its paper "Capital Cost and Performance Characteristics for Utility Scale Electric Generating Units." [5]

My focus in this analysis is addressing the difference in a NETL estimate and that of a full project cost that an owner would need to consider when presenting a project for approval to either its Board of Directors or Regulatory Authority. To demonstrate the difference, I look in detail at a NETL cost profile as compared to an engineering firm's full cost estimate prepared for the U.S. Energy Information Administration (EIA). [5] An attempt is made to provide some important definitions for the reader to understand the terms used. Also, specific differences in the scope of work are identified.

It is important to capture full project cost at the time of project initiation to obtain financing. The accuracy and detail of the estimate must be at least a Class 2 or Class 1 for project acceptance. The work presented by both NETL and Sargeant & Lundy in their full project cost estimates are Class 5 estimates and would not meet the standard required by the financial community. Lenders also look to both the technical maturity of the technology being offered and its application in similar projects to judge risk. An assessment is made of both duration and quality of performance guarantees, and proposed penalties for not meeting them. Since the life of these projects is generally 20 years or more, matching contractual terms such as rates of depreciation and power purchase agreements (PPAs) are required for all aspects of the projects.

In summary:

The NETL methodology is incomplete in determining full project costs for carbon capture and storage (CCS) projects. As outlined below, it is shown that this methodology does not include key project parameters which are required for the level of detail necessary to procure project financing. These items include fully-evaluated electrical, water, sewer, and natural gas connections. Also missing are performance wrap guarantees and sufficient owner and contractor contingency, as well as other line items identified in the report. In using the NETL methodology, the EPA has not provided a complete line by line cost analysis for CCS projects.

Executive Summary

The analysis presented below demonstrates the variance of costs that can be seen in different methodologies and scope definitions. Also included are the expected accuracy of the NETL estimates. It is then suggested that some consideration of sensitivity analysis, using both the high and low range of estimates, should be provided in the modelling. A clear definition of scope is important for decision makers to interpret results. It is concluded that, although the NETL estimating methodology is clearly defined and a good tool for comparing one technology solution to another, it is not complete enough in scope to capture full project costs. The EIA approach as demonstrated in the Sargeant & Lundy example is a better method to capture the cost of delivering these projects.

Analysis and Consideration

The following is a summary of the NETL Cost Estimation Guidelines, comparing it with an alternative pricing methodology used by the EIA to determine a similar project price, as provided in a report authored by Sargent & Lundy (February 2020). [5]

It is important to note that reference is made to Total Overnight Cost (TOC) of capital, which can be defined in different ways. One such definition of "overnight cost of capital" is provided here for reference, from the University of Calgary[6]:

> "When comparing the cost of building different types of electrical plants, firms will use various methods. For quick comparisons, firms will look at what the cost of building a plant overnight would be or the overnight cost of capital.[1] This is a hypothetical scenario because a plant cannot be constructed in one night, but it evaluates the cost of a plant if it were built right away, with current prices. This is used as a quick reference for the cost of a plant, because it does not consider the time it would take and how prices rise over time. The calculation is made without the interest rate, which would account for the rise in cost over time. The overnight cost is a very simple way to compare the cost of different plants.
>
> Some of the costs that go into the determination of the overnight are:
>
> - **Construction costs:** Installation of utilities for the plant, structural steel and other materials for the building, site planning etc.

- **Mechanical equipment supply and installation:** large pieces of machinery such as, boilers, cooling towers, steam turbines, condensers, photovoltaic modules, generators etc.
- **Electrical controls:** Equipment used to transform and transmit the electricity that is generated. Electrical transformers, switchyards, distributed control systems etc.
- **Project costs:** Costs that are incurred while the plant is being designed. Engineering costs, labor, scaffolding costs, construction management etc." [6]

It is noted that the NETL cost estimates do not always follow the definition above. As an example, NETL excludes electrical costs that are associated with the switchyard that by their definition are considered outside the fence. This is explained in more detail below.

Other cost definitions that are important to understand and are found on page 9 of NETL's 2021 QGESS for NETL Assessments of Power Plant Performance [3] are:

- **Total Plant Cost (TPC):** This is defined in the guidelines as Engineering, Procurement, Construction, and Commissioning (EPCC) cost plus project and process contingencies. In the document, NETL states that they use Engineering, Procurements, and Construction Management (EPCM) contracting costs as their base cost. This implies more risk to the owners, as the engineering firm is providing management services to the owner and the contracts remain with the owner. In the EPCC arrangement, the owner relinquishes control to the engineering firm, who then owns the contracts.
- **Total As-Spent Capital (TASC):** This comprises the sum of all capital expenditures as they incur during the capital expenditure period, including interest during construction. TASC is expressed in mixed current-year dollars over the construction and start up period to commercial operation. NETL assumes five years for coal plants and three years for gas plants.

These costs are outlined in the 2022 NETL "Cost and Performance Baseline for Fossil Energy Plants Volume 1: Bituminous Coal and Natural Gas to Electricity" document. [2] For example, page 16 provides an example of the cost of a state-of-the-art F Class natural gas combined cycle (NGCC) built in 2017. The NETL TOC in 2018$ is 952 $/kw. The NETL TASC in 2018$, however, is $1040/kw, 9.2% more in capital costs. This demonstrates the effect of including interest during construction in the estimate. The TASC are what the owner will pay.

Cost Estimate Classification

Most engineering and economic studies completed by NETL are cost estimates intended for the purpose of early project development deliverables only. These are often limited to use in feasibility studies/conceptual planning or concept screening, classified respectively as "Class 5" and "Class 4" estimate classes by the Association for the Advancement of Cost Engineering (AACE). The classification depends on numerous factors including the maturity of the technologies under evaluation, recent commercial experience, and nature of available cost data.

NETL class estimates related to pulverized coal (PC) power plants and NGCC power plants without carbon capture are AACE Class 4. All other cost estimates related to carbon capture and hydrogen are AACE Class 5. These are the estimates the EPA references. There is a concern that, with the current upsets on the supply side and shortage of skilled labor resulting from COVID 19, all the estimates would now be in the Class 5 category. The chart below is found on page 11 of NETL's 2021 Quality Guidelines for Energy Systems. [3]

Exhibit 2-2. Features of an AACE Class 4 and Class 5 cost estimates

Project Definition	Typical Engineering Completed	Expected Accuracy
1 to 15%	• Plant capacity, block schematics, indicated layout, process flow diagrams for main process • Systems and preliminary engineered process and utility • Equipment lists	**Class 4** -15% to +30%
0 to 2%	• Cost estimates (i.e., feasibility study) based on the level of engineering design performed • This range is deemed reflective of recent commercial power IGCC experience	**Class 5** -25% to +50%

For a project to proceed, at minimum, a Class 2 estimate would be recommended that would have a more limited spread of -5% to +20% expected accuracy. More likely, to receive financing, a Class 1 estimate of -3% to +15% would be required. Explanation of this classification matrix is provided in AACE "Cost Estimate Classification System – As Applied in Engineering, Procurement and Construction for the Process Industries." [7]

Capital Cost Contingencies

A process contingency is used to account for uncertainty within a project by adding in an amount of costs for unaccounted for or unforeseen events. An example would be during an excavation where bedrock is below expected levels, so additional fill needs to be removed. It is not clear in the NETL guidelines exactly what would be included for process contingency. On page 12 of the NETL guideline,[3] it states "Process contingency is typically not applied to costs that are set equal to research goal or programmatic target, since these values are generally intended to reflect the total cost."

Later in the same page, it states, "AACE International Recommended Practice No. 16R-90 "Conducting Technical and Economic Evaluations – As applied for the Process and Utility Industries,"(AACE 16R-90)" says that project contingency for a "budget-type" estimate (AACE Class 4 or 5) should be 15 to 30 percent of the sum of Bare Erected Costs (BEC); Engineering, Procurement, and Construction fees (EPC fees); and process contingency." [7] NETL then states that the owner's cost could be as high as 20% on top of the sum. In its Exhibit 2-4 on page 13, NETL further clarifies that it uses 15% of the Total Project Costs (TPC) as owner's contingency. This is based on information from a rule-of-thumb estimate from a 2019 professional

conversation with Black & Vetch on the topic. The use of these different percentages is confusing and addressed in the conclusions of this report.

Costs Not included by NETL Estimates

As with the capital cost contingencies estimates, it is important to note what is not included in NETL estimates related to owner's costs. They particularly stated on page 14 [3]:

"This lumped cost does not include:

- EPC risk premiums (costs estimates are based on an EPCM approach utilizing multiple subcontracts, in which the owner assumes project risks for performance, schedule, and cost).
- Transmission interconnection: the cost of interconnecting with power transmission infrastructure beyond the plant busbar.
- Taxes on capital costs: all capital costs are assumed to be exempt from state and local taxes.
- Unusual site improvements: normal costs associated with improvements to the plant site are included in the BEC, assuming that the site is level and requires no environmental remediation. Unusual costs associated with the following design parameters are excluded: flood plain considerations, existing soil/site conditions, water discharges and reuse, rainfall/snowfall criteria, seismic design, buildings/enclosures, fire protection, local code height requirements, noise regulations."

Other Costs

NETL details in the 2021 Quality Guidelines for Energy System Studies Cost Estimation Methodology for NETL Assessments of Power Plant Performance [3] that there are other key cost considerations that are not included in power plant cost estimation methodology. Notably, NETL uses a "fence line" reference description to determine the cost structure, terminating at the high voltage side of the main power transformer. This omits many items that would be normal costs for a typical project and need to be included, but that are unique to site conditions and interconnect requirements. Page 14 of NETL's guidelines details specifically:

> "Some typical examples of items outside the fence line include new access roads and railroad tracks; Upgrades to existing roads to accommodate increased traffic; Makeup water pipe outside the "fence line"; Landfill for on-site waste (slag) disposal; Natural gas line for back up fuel provisions; Plant switchyard; and Electrical transmission lines and substation."
>
> "All estimates are based on a reasonably standard plant. No unusual or extraordinary process equipment is included such as: Excessive water treatment equipment; Air-cooled condensers; Automatic coal reclamation."

> "Other items that are not addressed in the cost estimates are: Piles or caissons; Rock removal; Excessive dewatering; Expansive soil considerations; Excessive seismic considerations; Extreme temperature considerations; Hazardous or contaminated soils; Demolition or relocation of existing structures; Leasing of offsite land for parking or laydown; Busing of craft to site; Costs of offsite storage."

NETL comments "to the extent that these items are needed at specific sites, they should be explicitly included within the capital cost structure, rather than part of the contingency costs."

Experience would show most of the noted expenses would occur on any site in one form or another. If a Class 2 cost estimate were used, it would be expected that these items would not exceed the upper limit of 20% of the cost. A less detailed estimate, such as Class 5 or Class 4 estimates, could make a project more exposed to risk. An example would be estimating civil works, such as excavation and piles. A Class 5 estimate would not have detailed engineering completed at a level to fully define the civil works. In doing a Class 1 or Class 2 estimate, bore holes and soil samples would have been carried out to define the conditions for foundations.

EIA Estimates using Sargent & Lundy Capital Cost Study

To accurately reflect the changing costs for new electric power generators for EIA's Annual Energy Outlook 2020 report, EIA commissioned Sargent & Lundy to evaluate the capital cost and performance for 25 electric generating types. The following sections discuss the findings of this report for the case of a 650 MW unit with 90% capture as displayed in Appendix 2.

Methodology

Sargent & Lundy used a top-down capital cost estimate using both publicly available and internal sources to establish its cost parameters. It is an overnight capital cost estimate. The following is extracted from their report: "Capital Cost and Performance for Utility Scale Electric Generating Units" pages viii and ix [5]:

> "The capital cost estimates represent a complete power plant facility on a generic site at a non-specific U.S. location. As applicable, the basis of the capital costs is defined as all costs to engineer, procure, construct, and commission all equipment within the plant facility fence line. As described in the following section, we have also estimated location adjustments to help establish the cost impacts to project implementation in more specific areas or regions within the United States. Capital costs account for all costs incurred during construction of the power plant before the commercial online date. The capital costs are divided between engineering, procurement, and construction (EPC) contractor and owner's costs. Sargent & Lundy assumes that the power plant developer or owner will hire an EPC contractor for turnkey construction of the project. Unless noted otherwise, the estimates assume that the EPC contractor cost will include procurement of equipment, materials, and all construction labor associated with the project. The capital costs provided are overnight capital costs in 2019 price levels. Overnight capital costs represent the total cost a developer would expect to incur during the construction of a

project, excluding financing costs. The capital cost breakdowns for the EPC contractor are as follows:

- The civil and structural material and installation cost includes all material and associated labor for civil and structural tasks. This includes both labor and material for site preparation, foundation, piling, structural steel, and buildings.
- The mechanical equipment supply and installation cost includes all mechanical equipment and associated labor for mechanical tasks. This includes both labor and material for equipment installation such as pumps and tanks, piping, valves, and piping specialties.
- The electrical and instrumentation and controls supply, and installation includes all costs for transformers, switchgear, control systems, wiring, instrumentation, and raceway.
- The project indirect costs include engineering, construction management, and start-up and commissioning. The fees include contractor overhead costs, fees, and profit.

The owner's costs primarily consist of costs incurred to develop the project as well as land and utility interconnection costs. The owner's development costs include project development, studies, permitting, legal, owner's project management, owner's engineering, and owner's participation in startup and commissioning. Outside-the-fence-line costs are considered as owner's costs. These include electrical interconnection costs and natural gas interconnection and metering costs; however, these costs too are generic and based on nominal distances to substations and gas pipeline laterals. We have also assumed that no substation upgrades would be required for the electrical interconnection. Transmission costs are based on a one-mile transmission line (unless otherwise stated) with voltage ranging from 230 kilovolts (kV) to 500 kV depending on the unit capacity. Land requirements are based on typical land requirements for each technology with per-acreage costs based on a survey of typical site costs across the United States.

The overall project contingency is also included to account for undefined project scope and pricing uncertainty for both capital cost components and owner's cost components. The levels of contingency differ in some of the estimates based on the nature of the technology and the complexity of the technology implementation."

Comparison of Capital Cost Estimates by Sargent & Lundy Estimate and NETL Estimate

The NETL study uses case B128.90 on page 505 of their publication, "Cost and Performance Baseline Fossil Energy Plant Volume 1" [2] and included in Appendix 1. The Sargent & Lundy Case is from the EIA document, "Capital Cost and Performance Characteristics for Utility Scale Electric Generating Units," which is Case 3 on page 3-6 of the document [5] and included in Appendix 2.

The cost comparisons used and as discussed above were for a 650 MW Net Ultra – Supercritical Unit with 90% capture. These are similarly designed units, however cost estimated in two

different ways. The NETL estimate is a Class 5 estimate based on NETL guidelines discussed above. The Sargent & Lundy estimate is described as a generic location EPC estimate, but does not provide an AACE classification.

As explained in the Sargent & Lundy narrative above and as shown in Appendix 2, they developed a total overnight cost for an EPC contractor. This is fundamentally different than the NETL estimate, in that it includes project contingency values appropriate to offset risk that the contractor assumes when signing an EPC contract. The NETL estimate assumes an EPCM contact where the owner retains the risk. When looking at the contingency numbers, NETL include $368,875, while Sargent & Lundy estimate a contingency of $498,157. This could be a confirmation by Sargent & Lundy of the additional risk associated with EPCM that would apply to owner's cost. Also noted, the Sargent & Lundy estimate specifically identifies an owner's cost, but it is not identified as a line item in the NETL estimate.

Upon reviewing Appendix 2, the reader can see that many of the items listed on page 6 of this report as "items outside the fence line but normal cost additions for a project" are included in the Sargent & Lundy work. These are not included in the NETL estimate. Listed are costs for interconnection, both electrical and pipelines that are not in the NETL estimate.

Interest incurred during construction (IDC) is included in NETL's costs. For a coal unit it would be over 5 years. The Sargent & Lundy estimate uses an overnight cost, which does not include this financing. The concern is that including the interest in the NETL costs reduces the capital available for the project. Since every utility generally has its own cost of capital, it would be difficult to determine the appropriate costs using that method.

Results

In the previous comparisons, we have pointed out key components of the two methodologies used to determine project costs. The NETL method, although consistent and true to its guidelines, leaves out some major components of project costs. The assumption of EPCM contracting also puts risk on the owner for any overruns that might occur.

The result of this analysis for a 90% capture an ultra-super critical (USC) coal unit is two significantly different cost estimates. The NETL estimate is $3482/kw, while the Sargent & Lundy estimate is $5876/kw. This difference of 168% exceeds the high side of a Class 5 estimate. Examination of the details of the two estimates in the Appendix clearly shows that the addition to the scope required to make a full project cost is the difference.

Conclusion

The results of the review show that a full cost estimate provided by the Sargent & Lundy work can be substantially higher than an estimate that is provided by the NETL guidelines. While NETL costs estimates and methodologies are used to compare one technology option to another and do this consistently and fairly, a unit owner is exposed to full project costs and risks not fully captured by these NETL assumptions. Notably, capital cost contingencies, owner's costs, and outside the fence line costs that are necessary parts of a project are not fully accounted. When

evaluating the cost of capital for major infrastructure projects, such as carbon capture systems, a more complete "all-in cost" estimate would be more appropriate.

An example of an area of concern would be using a contingency of 16.4 % of Total Project Cost, which includes Process and Total Project Contingency, as seen in Appendix 1 below. This seems to be a low estimate, especially given the NETL assumption: "All estimates are based on reasonable standard plant design. No unusual or extraordinary process equipment is included," as stated on page 14 of the reference document. [3] The AACE guidelines "Conducting Technical and Economic Evaluation as Applied to Process and Utility Industry" [7] identifies that contingency could be between 15% to 30%.

It is important that full project costs be captured and understood to reduce the owner's risk prior to acquiring financing. The EIA estimate as provided by Sargent & Lundy shows a more complete accounting of project costs. Unfortunately, this is only a Class 5 estimate. In order to obtain financing or regulatory approval, the project owner must obtain a Class 2 estimate, and, in today's climate, a Class 1 or better estimate would be required.

Listed below are the main findings from this review and expressed concerns on how the NETL methodology is applied.

- The NETL Methodology is incomplete in determining full project costs for CCS projects. As outlined within this document, it is shown that methodology does not include key project parameters which are required for the detail necessary to procure project financing. These items include fully evaluated electrical, water, sewer, and natural gas connections. Also missing are performance wrap guarantees, and sufficient owner and contractor contingency, as well as other line items identified in the report.
- In using the NETL methodology, which works well only as a price comparison for different types of technology, the EPA has not provided a complete line by line cost analysis for CCS projects.
- Because the EPA used the NETL methodology, the EPA has not identified the full project cost as seen by the owner. An example of this is demonstrated above in the capital cost comparison. Here, the NETL methodology does not identify a clear overnight cost. Each entity will determine its own cost of treating interest during construction, according to the project schedule. This would then be presented as the project cost.

When running the IPM model, specific attention should be given to the accuracy of AACE Class 4 and Class 5 estimates. It is recommended that sensitivity analysis should be carried out for the high and low side of both the NETL and Sargent & Lundy estimates, using AACE Class 5 ranges. This would provide a better assessment of risk associated with the various technical options available.

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About the Author

Mr. Doug Campbell, FTB Energy Solutions, Inc.

Mr. Doug Campbell is a professional engineer with demonstrated managerial ability including planning, financial control, contract management, staff supervision and reporting. Over a 48-year career, Mr. Campbell has developed a wide range of technical skills associated with the design construction and start-up of new generation and the operation and maintenance of existing generation facilities. He has held positions as Manager of Hydro, Manager of a Multi-unit Steam Plant and Combustion Turbine operation, as well as Director of Generation Services in a vertically-integrated utility. As a Senior Technical Advisor, Mr. Campbell contributed to various engineering problems, such as recent studies on inspection and evaluation of fitness for service for high pressure equipment and various pressure retaining component parts. His involvement as

an independent contractor has been in providing expert advice on new and developing technologies to support the transformation of the electrical grid. Current work includes providing insights in these developments, especially as related to a low carbon world. Mr. Campbell completed a Master of Science in Energy from Heriot-Watt University in 2018 and a Master of Applied Economics from Saint Mary's University in 2022, which has allowed him to obtain additional skills to evaluate technology and to comment on the strategic outcomes of their application.

Appendix 1: NETL Estimate

COST AND PERFORMANCE BASELINE FOR FOSSIL ENERGY PLANTS VOLUME 1: BITUMINOUS COAL AND NATURAL GAS TO ELECTRICITY

Exhibit 4-89. Case B12B.90 total plant cost details

Case:		B12B.90	– SC PC w/ CO_2 Capture				Estimate Type:			Conceptual	
Plant Size (MW, net):		650					Cost Base:			Dec 2018	
Item No.	Description	Equipment Cost	Material Cost	Labor		Bare Erected Cost	Eng'g CM H.O. & Fee	Contingencies		Total Plant Cost	
				Direct	Indirect			Process	Project	$/1,000	$/kW
	1	Coal & Sorbent Handling									
1.1	Coal Receive & Unload	$1,174	$0	$529	$0	$1,702	$298	$0	$300	$2,300	$4
1.2	Coal Stackout & Reclaim	$3,853	$0	$861	$0	$4,714	$825	$0	$830	$6,369	$10
1.3	Coal Conveyors	$35,499	$0	$8,443	$0	$43,943	$7,690	$0	$7,745	$59,377	$91
1.4	Other Coal Handling	$4,932	$0	$1,037	$0	$5,969	$1,045	$0	$1,052	$8,066	$12
1.5	Sorbent Receive & Unload	$225	$0	$67	$0	$293	$51	$0	$52	$396	$1
1.6	Sorbent Stackout & Reclaim	$1,650	$0	$298	$0	$1,949	$341	$0	$343	$2,633	$4
1.7	Sorbent Conveyors	$2,500	$544	$605	$0	$3,649	$639	$0	$643	$4,931	$8
1.8	Other Sorbent Handling	$120	$28	$62	$0	$211	$37	$0	$37	$285	$0
1.9	Coal & Sorbent Handling Foundations	$0	$1,630	$2,148	$0	$3,778	$661	$0	$666	$5,105	$8
	Subtotal	**$49,954**	**$2,202**	**$14,051**	**$0**	**$66,207**	**$11,586**	**$0**	**$11,669**	**$89,462**	**$138**
	2	Coal & Sorbent Preparation & Feed									
2.1	Coal Crushing & Drying	$2,522	$0	$484	$0	$3,006	$526	$0	$530	$4,062	$6
2.2	Prepared Coal Storage & Feed	$8,488	$0	$1,828	$0	$10,315	$1,805	$0	$1,818	$13,938	$21
2.5	Sorbent Preparation Equipment	$1,110	$48	$227	$0	$1,386	$242	$0	$244	$1,872	$3
2.6	Sorbent Storage & Feed	$1,861	$0	$702	$0	$2,563	$449	$0	$452	$3,463	$5
2.9	Coal & Sorbent Feed Foundation	$0	$737	$646	$0	$1,383	$242	$0	$244	$1,869	$3
	Subtotal	**$13,981**	**$785**	**$3,887**	**$0**	**$18,653**	**$3,264**	**$0**	**$3,288**	**$25,205**	**$39**
	3	Feedwater & Miscellaneous BOP Systems									
3.1	Feedwater System	$3,973	$6,811	$3,406	$0	$14,190	$2,483	$0	$2,501	$19,175	$29
3.2	Water Makeup & Pretreating	$7,880	$788	$4,465	$0	$13,133	$2,298	$0	$3,086	$18,517	$28
3.3	Other Feedwater Subsystems	$3,101	$1,017	$966	$0	$5,084	$890	$0	$896	$6,870	$11
3.4	Service Water Systems	$2,489	$4,751	$15,384	$0	$22,623	$3,959	$0	$5,316	$31,898	$49
3.5	Other Boiler Plant Systems	$767	$279	$698	$0	$1,744	$305	$0	$307	$2,357	$4
3.6	Natural Gas Pipeline and Start-Up System	$3,341	$144	$108	$0	$3,592	$629	$0	$633	$4,854	$7
3.7	Waste Water Treatment Equipment	$12,932	$0	$7,926	$0	$20,858	$3,650	$0	$4,902	$29,409	$45
3.8	Spray Dryer Evaporator	$16,923	$0	$9,798	$0	$26,721	$4,676	$0	$6,280	$37,677	$58
3.9	Miscellaneous Plant Equipment	$225	$30	$115	$0	$370	$65	$0	$87	$521	$1
	Subtotal	**$51,632**	**$13,819**	**$42,864**	**$0**	**$108,315**	**$18,955**	**$0**	**$24,008**	**$151,278**	**$233**
	4	Pulverized Coal Boiler & Accessories									
4.9	Pulverized Coal Boiler & Accessories	$268,021	$0	$152,717	$0	$420,738	$73,629	$0	$74,155	$568,522	$874
4.10	Selective Catalytic Reduction System	$30,239	$0	$17,267	$0	$47,506	$8,314	$0	$8,373	$64,193	$99
4.11	Boiler Balance of Plant	$1,763	$0	$1,005	$0	$2,768	$484	$0	$488	$3,740	$6
4.12	Primary Air System	$1,692	$0	$964	$0	$2,657	$465	$0	$468	$3,590	$6
4.13	Secondary Air System	$2,563	$0	$1,461	$0	$4,024	$704	$0	$709	$5,437	$8

Case:		B12B.90	– SC PC w/ CO_2 Capture				Estimate Type:			Conceptual	
Plant Size (MW, net):		650					Cost Base:			Dec 2018	
Item No.	Description	Equipment Cost	Material Cost	Labor		Bare Erected Cost	Eng'g CM H.O. & Fee	Contingencies		Total Plant Cost	
				Direct	Indirect			Process	Project	$/1,000	$/kW
4.14	Induced Draft Fans	$5,530	$0	$3,151	$0	$8,680	$1,519	$0	$1,530	$11,729	$18
4.15	Major Component Rigging	$93	$0	$53	$0	$146	$25	$0	$26	$197	$0
4.16	Boiler Foundations	$0	$398	$350	$0	$748	$131	$0	$132	$1,011	$2
	Subtotal	**$309,901**	**$398**	**$176,967**	**$0**	**$487,267**	**$85,272**	**$0**	**$85,881**	**$658,420**	**$1,012**
	5					**Flue Gas Cleanup**					
5.1	CANSOLV Carbon Dioxide (CO_2) Removal System	$141,501	$62,150	$130,515	$0	$334,167	$58,479	$56,808	$78,654	$528,109	$812
5.2	WFGD Absorber Vessels & Accessories	$79,280	$0	$16,957	$0	$96,237	$16,841	$0	$16,962	$130,040	$200
5.3	Other FGD	$1,263	$0	$972	$0	$2,235	$391	$0	$394	$3,021	$5
5.4	Carbon Dioxide (CO_2) Compression & Drying	$42,506	$6,376	$14,212	$0	$63,093	$11,041	$0	$14,827	$88,962	$137
5.5	Carbon Dioxide (CO_2) Compressor Aftercooler	$467	$74	$200	$0	$741	$130	$0	$174	$1,045	$2
5.6	Mercury Removal (Dry Sorbent Injection/Activated Carbon Injection)	$2,661	$585	$2,617	$0	$5,863	$1,026	$0	$1,033	$7,923	$12
5.9	Particulate Removal (Bag House & Accessories) (included with 5.2)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5.12	Gas Cleanup Foundations	$0	$197	$173	$0	$370	$65	$0	$65	$500	$1
5.13	Gypsum Dewatering System	$762	$0	$128	$0	$890	$156	$0	$157	$1,203	$2
	Subtotal	**$268,440**	**$69,383**	**$165,774**	**$0**	**$503,597**	**$88,129**	**$56,808**	**$112,267**	**$760,802**	**$1,170**
	7					**Ductwork & Stack**					
7.3	Ductwork	$0	$746	$518	$0	$1,264	$221	$0	$223	$1,708	$3
7.4	Stack	$8,814	$0	$5,122	$0	$13,936	$2,439	$0	$2,456	$18,831	$29
7.5	Duct & Stack Foundations	$0	$210	$249	$0	$459	$80	$0	$108	$647	$1
	Subtotal	**$8,814**	**$956**	**$5,889**	**$0**	**$15,659**	**$2,740**	**$0**	**$2,787**	**$21,186**	**$33**
	8					**Steam Turbine & Accessories**					
8.1	Steam Turbine Generator & Accessories	$72,900	$0	$8,124	$0	$81,024	$14,179	$0	$14,280	$109,484	$168
8.2	Steam Turbine Plant Auxiliaries	$1,654	$0	$3,522	$0	$5,176	$906	$0	$912	$6,994	$11
8.3	Condenser & Auxiliaries	$11,146	$0	$3,782	$0	$14,928	$2,612	$0	$2,631	$20,172	$31
8.4	Steam Piping	$43,007	$0	$17,430	$0	$60,437	$10,576	$0	$10,652	$81,666	$126
8.5	Turbine Generator Foundations	$0	$258	$427	$0	$685	$120	$0	$161	$966	$1
	Subtotal	**$128,707**	**$258**	**$33,285**	**$0**	**$162,251**	**$28,394**	**$0**	**$28,637**	**$219,281**	**$337**
	9					**Cooling Water System**					
9.1	Cooling Towers	$19,149	$0	$5,922	$0	$25,072	$4,388	$0	$4,419	$33,878	$52
9.2	Circulating Water Pumps	$2,697	$0	$198	$0	$2,896	$507	$0	$510	$3,913	$6
9.3	Circulating Water System Auxiliaries	$16,029	$0	$2,115	$0	$18,143	$3,175	$0	$3,198	$24,516	$38
9.4	Circulating Water Piping	$0	$7,410	$6,710	$0	$14,120	$2,471	$0	$2,489	$19,079	$29

Case:		B12B.90	– SC PC w/ CO_2 Capture				Estimate Type:			Conceptual	
Plant Size (MW, net):		650					Cost Base:			Dec 2018	
Item No.	Description	Equipment Cost	Material Cost	Labor		Bare Erected Cost	Eng'g CM H.O. & Fee	Contingencies		Total Plant Cost	
				Direct	Indirect			Process	Project	$/1,000	$/kW
9.5	Make-up Water System	$1,241	$0	$1,594	$0	$2,834	$496	$0	$500	$3,830	$6
9.6	Component Cooling Water System	$1,155	$0	$886	$0	$2,040	$357	$0	$360	$2,757	$4
9.7	Circulating Water System Foundations	$0	$691	$1,148	$0	$1,839	$322	$0	$432	$2,593	$4
	Subtotal	**$40,271**	**$8,101**	**$18,572**	**$0**	**$66,944**	**$11,715**	**$0**	**$11,907**	**$90,566**	**$139**
	10	**Ash & Spent Sorbent Handling Systems**									
10.6	Ash Storage Silos	$1,170	$0	$3,578	$0	$4,747	$831	$0	$837	$6,415	$10
10.7	Ash Transport & Feed Equipment	$3,977	$0	$3,943	$0	$7,920	$1,386	$0	$1,396	$10,701	$16
10.9	Ash/Spent Sorbent Foundation	$0	$813	$1,001	$0	$1,814	$317	$0	$426	$2,558	$4
	Subtotal	**$5,146**	**$813**	**$8,521**	**$0**	**$14,481**	**$2,534**	**$0**	**$2,659**	**$19,674**	**$30**
	11	**Accessory Electric Plant**									
11.1	Generator Equipment	$2,658	$0	$2,005	$0	$4,663	$816	$0	$822	$6,300	$10
11.2	Station Service Equipment	$7,505	$0	$644	$0	$8,148	$1,426	$0	$1,436	$11,010	$17
11.3	Switchgear & Motor Control	$11,650	$0	$2,021	$0	$13,671	$2,392	$0	$2,410	$18,473	$28
11.4	Conduit & Cable Tray	$0	$1,514	$4,364	$0	$5,879	$1,029	$0	$1,036	$7,944	$12
11.5	Wire & Cable	$0	$4,011	$7,169	$0	$11,180	$1,956	$0	$1,970	$15,107	$23
11.6	Protective Equipment	$55	$0	$191	$0	$246	$43	$0	$43	$332	$1
11.7	Standby Equipment	$823	$0	$760	$0	$1,583	$277	$0	$279	$2,139	$3
11.8	Main Power Transformers	$6,966	$0	$142	$0	$7,108	$1,244	$0	$1,253	$9,605	$15
11.9	Electrical Foundations	$0	$221	$563	$0	$784	$137	$0	$184	$1,106	$2
	Subtotal	**$29,657**	**$5,747**	**$17,859**	**$0**	**$53,262**	**$9,321**	**$0**	**$9,434**	**$72,017**	**$111**
	12	**Instrumentation & Control**									
12.1	Pulverized Coal Boiler Control Equipment	$803	$0	$143	$0	$946	$166	$0	$167	$1,278	$2
12.3	Steam Turbine Control Equipment	$719	$0	$80	$0	$799	$140	$0	$141	$1,080	$2
12.5	Signal Processing Equipment	$911	$0	$162	$0	$1,074	$188	$0	$189	$1,451	$2
12.6	Control Boards, Panels & Racks	$279	$0	$170	$0	$449	$79	$22	$82	$632	$1
12.7	Distributed Control System Equipment	$7,864	$0	$1,402	$0	$9,266	$1,622	$463	$1,703	$13,053	$20
12.8	Instrument Wiring & Tubing	$551	$441	$1,762	$0	$2,753	$482	$138	$506	$3,879	$6
12.9	Other Instrumentation & Controls Equipment	$677	$0	$1,568	$0	$2,245	$393	$112	$412	$3,162	$5
	Subtotal	**$11,803**	**$441**	**$5,288**	**$0**	**$17,531**	**$3,068**	**$736**	**$3,200**	**$24,535**	**$38**
	13	**Improvements to Site**									
13.1	Site Preparation	$0	$462	$9,804	$0	$10,266	$1,797	$0	$2,412	$14,475	$22
13.2	Site Improvements	$0	$2,283	$3,017	$0	$5,300	$928	$0	$1,246	$7,474	$11
13.3	Site Facilities	$2,609	$0	$2,737	$0	$5,346	$935	$0	$1,256	$7,537	$12
	Subtotal	**$2,609**	**$2,745**	**$15,558**	**$0**	**$20,912**	**$3,660**	**$0**	**$4,914**	**$29,486**	**$45**
	14	**Buildings & Structures**									
14.2	Boiler Building	$0	$11,598	$10,193	$0	$21,791	$3,813	$0	$3,841	$29,445	$45
14.3	Steam Turbine Building	$0	$16,121	$15,014	$0	$31,136	$5,449	$0	$5,488	$42,072	$65

Case:		B12B.90	– SC PC w/ CO_2 Capture				Estimate Type:			Conceptual	
Plant Size (MW, net):		650					Cost Base:			Dec 2018	
Item No.	Description	Equipment Cost	Material Cost	Labor		Bare Erected Cost	Eng'g CM H.O. & Fee	Contingencies		Total Plant Cost	
				Direct	Indirect			Process	Project	$/1,000	$/kW
14.4	Administration Building	$0	$1,047	$1,107	$0	$2,154	$377	$0	$380	$2,911	$4
14.5	Circulation Water Pumphouse	$0	$184	$146	$0	$330	$58	$0	$58	$446	$1
14.6	Water Treatment Buildings	$0	$460	$419	$0	$880	$154	$0	$155	$1,189	$2
14.7	Machine Shop	$0	$553	$371	$0	$923	$162	$0	$163	$1,247	$2
14.8	Warehouse	$0	$416	$416	$0	$832	$146	$0	$147	$1,124	$2
14.9	Other Buildings & Structures	$0	$290	$247	$0	$537	$94	$0	$95	$726	$1
14.10	Waste Treating Building & Structures	$0	$642	$1,945	$0	$2,587	$453	$0	$456	$3,496	$5
	Subtotal	**$0**	**$31,312**	**$29,859**	**$0**	**$61,170**	**$10,705**	**$0**	**$10,781**	**$82,657**	**$127**
	Total	**$920,915**	**$136,959**	**$538,376**	**$0**	**$1,596,250**	**$279,344**	**$57,544**	**$311,431**	**$2,244,569**	**$3,452**

Appendix 2:
EIA/Sargent & Lundy Estimate Reference EIA Cost and Performance Characteristic Estimates for Utility Scale Electric Generation Technologies

EIA – Capital Cost Estimates – 2019 $s			
Configuration			650 MW Net, Ultra-Supercritical Coal w/ 90% Carbon Capture 1 x 831 MW Gross
Combustion Emissions Controls			Low NOx Burners / OFA
Post-Combustion Emissions Controls			SCR / Baghouse/ WFGD / WESP / AMINE Based CCS 90%
Fuel Type			High Sulfur Bituminous
	Units		
Plant Characteristics			
Net Plant Capacity (60 deg F, 60% RH)	MW		650
Heat Rate, HHV Basis	Btu/kWh		12507
Capital Cost Assumptions			
EPC Contracting Fee	% of Direct & Indirect Costs		10%
Project Contingency	% of Project Costs		15%
Owner's Services	% of Project Costs		5%
Estimated Land Requirement (acres)	$		300
Estimated Land Cost ($/acre)	$		30,000
Interconnection Costs			
Electrical Transmission Line Costs	$/mile		2,520,000
Miles	miles		1.00
Substation Expansion	$		0
Gas Interconnection Costs			
Pipeline Cost	$/mile		2,500,000
Miles	miles		0.50
Metering Station	$		3,600,000
Typical Project Timelines			
Development, Permitting, Engineering	months		24
Plant Construction Time	months		36
Total Lead Time Before COD	months		60
Operating Life	years		40
Cost Components (Note 1)		**Breakout**	**Total**
Civil/Structural/Architectural Subtotal	$		311,200,000
Mechanical – Boiler Plant	$	967,433,333	
Mechanical – Turbine Plant	$	242,533,333	
Mechanical – Balance of Plant	$	92,077,778	
Mechanical Subtotal	$		1,302,044,444
Electrical – Main Power System	$	26,350,000	
Electrical – Aux Power System	$	31,050,000	
Electrical – BOP and I&C	$	113,150,000	
Electrical – Substation and Switchyard	$	23,350,000	
Electrical Subtotal	$		193,900,000
CCS Plant Subtotal	$		663,846,000
Project Indirects	$		390,200,000
EPC Total Before Fee	$		2,861,190,000
EPC Fee	$		286,119,000
EPC Subtotal	$		3,147,309,000
Owner's Cost Components (Note 2)			
Owner's Services	$		157,365,000
Land	$		9,000,000
Electrical Interconnection	$		2,520,000
Gas Interconnection	$		4,850,000

Case 3 EIA – Capital Cost Estimates – 2019 $s		
Configuration		650 MW Net, Ultra-Supercritical Coal w/ 90% Carbon Capture 1 x 831 MW Gross
Combustion Emissions Controls		Low NOx Burners / OFA
Post-Combustion Emissions Controls		SCR / Baghouse/ WFGD / WESP / AMINE Based CCS 90%
Fuel Type		High Sulfur Bituminous
	Units	
Owner's Cost Subtotal	$	173,735,000
Project Contingency	$	498,157,000
Total Capital Cost	$	3,819,201,000
	$/kW net	5,876
Capital Cost Notes		
1. Costs based on EPC contracting approach. Direct costs include equipment, material, and labor to construct the civil/structural, mechanical, and electrical/I&C components of the facility. Indirect costs include distributable material and labor costs, cranes, scaffolding, engineering, construction management, startup and commissioning, and contractor overhead. EPC fees are applied to the sum of direct and indirect costs. 2. Owner's costs include project development, studies, permitting, legal, owner's project management, owner's engineering, and owner's startup and commissioning costs. Other owner's costs include electrical interconnection costs, gas interconnection costs (if applicable), and land acquisition costs.		

Attachment I

TECHNICAL COMMENTS ON HYDROGEN AND AMMONIA FIRING

REGARDING:

EPA'S PROPOSAL ENTITLED "NEW SOURCE PERFORMANCE STANDARDS FOR GHG EMISSIONS FROM NEW AND RECONSTRUCTED EGUS; EMISSION GUIDELINES FOR GHG EMISSIONS FROM EXISTING EGUS; AND REPEAL OF THE AFFORDABLE CLEAN ENERGY RULE" (DOCKET EPA-HQ-OAR-2023-0072)

PREPARED FOR:

NATIONAL RURAL ELECTRIC COOPERATIVE ASSOCIATION

PREPARED BY:

KIEWIT ENGINEERING GROUP, INC.

AUGUST 4, 2023

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1. ANALYSIS OF EPA'S TECHNICAL SUPPORT DOCUMENT

This section of the report will discuss two of the Environmental Protection Agency's (EPA) Technical Support Documents:

- Resource Adequacy Analysis
- Hydrogen in Combustion Turbine Electric Generating Units

1.1 RESOURCE ADEQUACY ANALYSIS

The Technical Support Documents for EPA's proposed "New Source Performance Standards for GHG Emissions from New and Reconstructed EGUs; Emission Guidelines for GHG Emissions from Existing EGUs; and Repeal of the Affordable Clean Energy Rule" ("proposed EPA CO2 Rule") are based on the Integrated Planning Model (IPM) model. They developed two cases: a post-Inflation Reduction Act (IRA) 2022 Reference case and a Proposal case, which models the impact of EPA's rule. The proposal case is summarized in table below.

EPA: CO2 Rule, Proposal Case, Resource Adequacy	2028	2030	2035	2040	2045	2050	2055
1. Reserve Margin Capacity Summer [MW]	926,851	950,216	1,016,190	1,093,695	1,182,107	1,280,223	1,359,074
Plus Firm Contract Purchases Summer [MW]	0	0	0	0	0	0	0
Plus Transmission In Summer [MW]	100,391	98,069	99,476	99,293	124,498	146,303	151,862
Less Firm Contract Sales Summer [MW]	0	0	0	0	0	0	0
Less Transmission Out Summer [MW]	96,561	93,756	93,611	92,304	118,358	141,362	147,196
Total Reserve Margin Capacity Summer [MW]	**930,682**	**954,529**	**1,022,056**	**1,100,684**	**1,188,246**	**1,285,164**	**1,363,740**
Accredited Capability (MW)	1,733,344	1,777,388	1,901,950	2,047,662	2,212,026	2,394,207	2,541,250
2. Peak Load Summer [MW]	**806,492**	**827,172**	**885,760**	**953,967**	**1,029,920**	**1,113,984**	**1,182,176**
Less DSM [MW]	0	0	0	0	0	0	0
Net Demand Summer [MW]	**806,492**	**827,172**	**885,760**	**953,967**	**1,029,920**	**1,113,984**	**1,182,176**
Peak Load Growth (%/year)		1.27%	1.38%	1.49%	1.54%	1.58%	1.20%
3. Reserve Margin Summer [%]	**15**	**15**	**15**	**15**	**15**	**15**	**15**

To expand on this information, we provide a comparison of the Proposal case (vs. Reference Case) through 2035 is shown in tables below.

The first table shows the Reference Case.

EPA: New CO2 Rule (5/11/2023), Reference Case, Capacity Additions (MW)								
	2028	2030	2035	2040	2045	2050	Total MW	MW/Yr
New_Coal_CCS	0	9,338	1,351	0	0	0	10,689	1,527
New_Gas_CCS	0	6,662	3,713	0	0	0	10,375	1,482
Retrofit Coal_CCS	0	16,000	5,064	0	0	0	21,064	3,009
Retrofit Gas_CCS	0	0	0	0	0	0	0	0
Total_CCS	**0**	**31,999**	**10,129**	**0**	**0**	**0**	**42,128**	**6,018**
Retire_Coal	56,296	24,855	23,068	8,803	13,672	12,145	138,838	5,142
Retire_Gas	1,695	733	3,797	639	14,648	14,542	36,055	1,335
Total_Retire_CG	**57,991**	**25,588**	**26,865**	**9,442**	**28,320**	**26,687**	**174,893**	**6,478**
New_Gas_CC	33,685	0	3,167	286	116	2,939	40,193	1,489
New_Gas_CT	13,812	0	10,222	43,528	94,760	106,386	268,707	9,952
Total_New_Gas	**47,497**	**0**	**13,389**	**43,814**	**94,876**	**109,325**	**308,901**	**11,441**
Gas ($/MMBtu)	$3.02	$2.53	$2.10	$2.19	$2.13	$1.91	$2.31	
Source: EPA, Post-IRA 2022 Reference Case, Integrated Planning Model (5/11/2023)								

The second table shows the proposal case.

EPA: New CO2 Rule (5/11/2023), Proposal Case, Capacity Additions (MW)								
	2028	2030	2035	2040	2045	2050	Total MW	MW/Yr
New_Coal_CCS	0	12,104	6	0	0	0	12,111	1,730
New_Gas_CCS	0	4,188	3,855	0	0	0	8,043	1,149
Retrofit Coal_CCS	0	16,293	3,861	0	0	0	20,154	2,879
Retrofit Gas_CCS	0	0	0	0	0	0	0	0
Total_CCS	**0**	**32,586**	**7,722**	**0**	**0**	**0**	**40,308**	**2,118**
Retire_Coal	57,758	23,626	44,988	3,655	9,028	158	139,213	5,156
Retire_Gas	1,695	1,162	3,595	574	14,693	14,461	36,181	1,340
Total_Retire_CG	**59,454**	**24,788**	**48,584**	**4,229**	**23,721**	**14,619**	**175,394**	**6,496**
New_Gas_CC	37,193	0	686	341	727	2,439	41,386	1,533
New_Gas_CT	13,990	123	33,048	38,638	89,406	96,079	271,283	10,048
Total_New_Gas	**51,183**	**123**	**33,734**	**38,979**	**90,133**	**98,518**	**312,669**	**11,580**
Gas ($/MMbtu)	$3.02	$2.76	$2.05	$2.14	$2.12	$1.88	$2.33	
Hydrogen ($/MMbtu)	$0.00	$7.40	$3.70	$3.70	$3.70	$3.70	$3.70	
New H2-CCGT (MW)	0	233	10,382	1,997	632	7,887	**21,131**	1,057
New H2-CCGT (Tbtu)	0	3	294	347	58	80		
EPA Peak Demand	**806,492**	**827,172**	**885,760**	**953,967**	**1,029,920**	**1,113,987**	**307,495**	**1.5%**
Source: EPA, CO2 Rule, Proposal Case, Integrated Planning Model (5/11/2023)								

Of these projected NGCC builds, 6.4 GW are to co-fire hydrogen under the Proposal case. Using the methodology outlined above, EPA estimated that in 2040, approximate 2 GW of capacity increased hydrogen co-fire blends to 96% by volume while the remaining capacity reduced dispatch to below 50% under the Proposal case.

EPA did not analyze the impacts of gas-CCS as a compliance measure within this subcategory, which is not helpful to the industry in trying to evaluate the impact to manufacturing and construction resources. It is not possible to determine how much hydrogen production will be needed without determining how many plants are expected to implement CCS instead of using hydrogen to achieve compliance.

EPA estimated that in 2040 approximately 2 GW of capacity increased hydrogen co-fire blends to 96% by volume and the remaining capacity reduced dispatch to below 50% capacity factor. About 80% of the reduction in generation were apportioned to existing NGCC units operating below 50% capacity factor and the remaining 20% apportioned to incremental non-emitting resources. The decreases in generation from affected new NGCC units are offset by increases in replacement generation.

The net result is that utilities would need to expend significant capital to comply with this rule. Since the volumes of hydrogen are likely to be limited, the ability to satisfy 96% hydrogen firing for a 300 MW plant with greater than 50% capacity factor will be challenging. Therefore, the remaining choices for compliance will be to reduce capacity factor to less than 50% or implement CCS. In the case of reducing capacity factor to less than 50%, additional generating capacity will have to be brought online to meet electricity demand or existing, less efficient generation will have to increase its output. The result is that no decrease, or even an overall increase, in emissions will occur, and a duplication or overbuilding of plants required to meet overall capacity demands will occur instead. Bottom line, the regulations will likely result in a lot of units, including a lot of new units running below 50% capacity. Thus, this modeling shows the potential flaws of EPA's rule which are likely to significantly increase costs and decrease efficiency of capital without achieving any emissions reductions.

1.1.1 FORECAST COMPARISON OF EPA TO EIA

U.S. Energy Information Administration (EIA) in March 2023 released their Reference Case for the EIA 2023 Annual Energy Outlook, which includes the Inflation Reduction Act (IRA) tax credits, with new generation capacity additions for fossil generation summarized below. Since it came out in March, it does not include the EPA's GHG rule. However, it is relevant to compare to the EPA's numbers because the EIA's forecast is used by the entire power industry as a benchmark for future forecasting. The EIA uses its NEMS model for forecasting, while the EPA uses its own IPM model. The NEMS model has several advantages over the IPM model, which is why it is the standard bearer for the industry. One of the significant differences between the two models is that the NEMS model accounts for demand side management. Utilities use demand side management to cost effectively limit the amount of generation they need to build and burden the rate payers with. It is a valuable tool for managing the grid and the fact that it is not in the IPM model is a significant limitation of EPA's model.

Below is the EIA forecast.

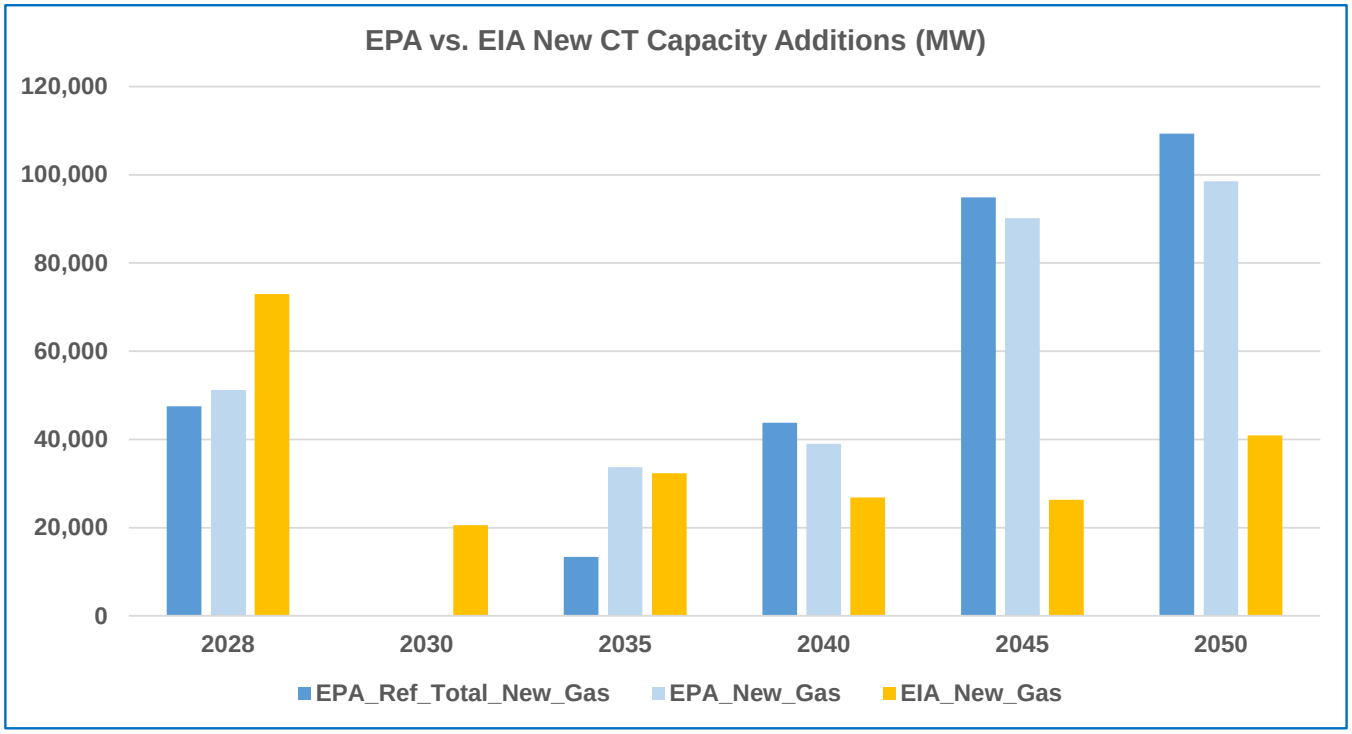
EIA: Reference Case (3/17/2023), Fossil Generation Additions (MW)								
	2028	2030	2035	2040	2045	2050	Total MW	MW/Yr
New_Coal_CCS	0	0	0	0	0	0	0	0
New_Gas_CCS	0	0	0	0	0	0	0	0
Retrofit Coal_CCS	0	0	0	0	0	0	0	0
Retrofit Gas_CCS	0	0	0	0	0	0	0	0
Total_CCS	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
Retire_Coal	0	24,519	10,949	14,119	2,184	4,344	56,116	2,806
Retire_Gas	0	1,590	8,349	466	2,061	2,243	14,709	735
Total_Retire_CG	**0**	**26,109**	**19,298**	**14,585**	**4,245**	**6,587**	**70,824**	**3,541**
New_Gas_CC	18,790	3,296	4,651	1,807	217	10,670	39,432	1,460
New_Gas_CT	54,178	17,246	27,672	25,053	26,074	30,236	180,458	6,684
Total_New_Gas	**72,968**	**20,542**	**32,323**	**26,860**	**26,291**	**40,906**	**219,890**	**8,144**
Source: EIA, 2023 Annual Energy Outlook, NEMS Model (3/17/2023)								

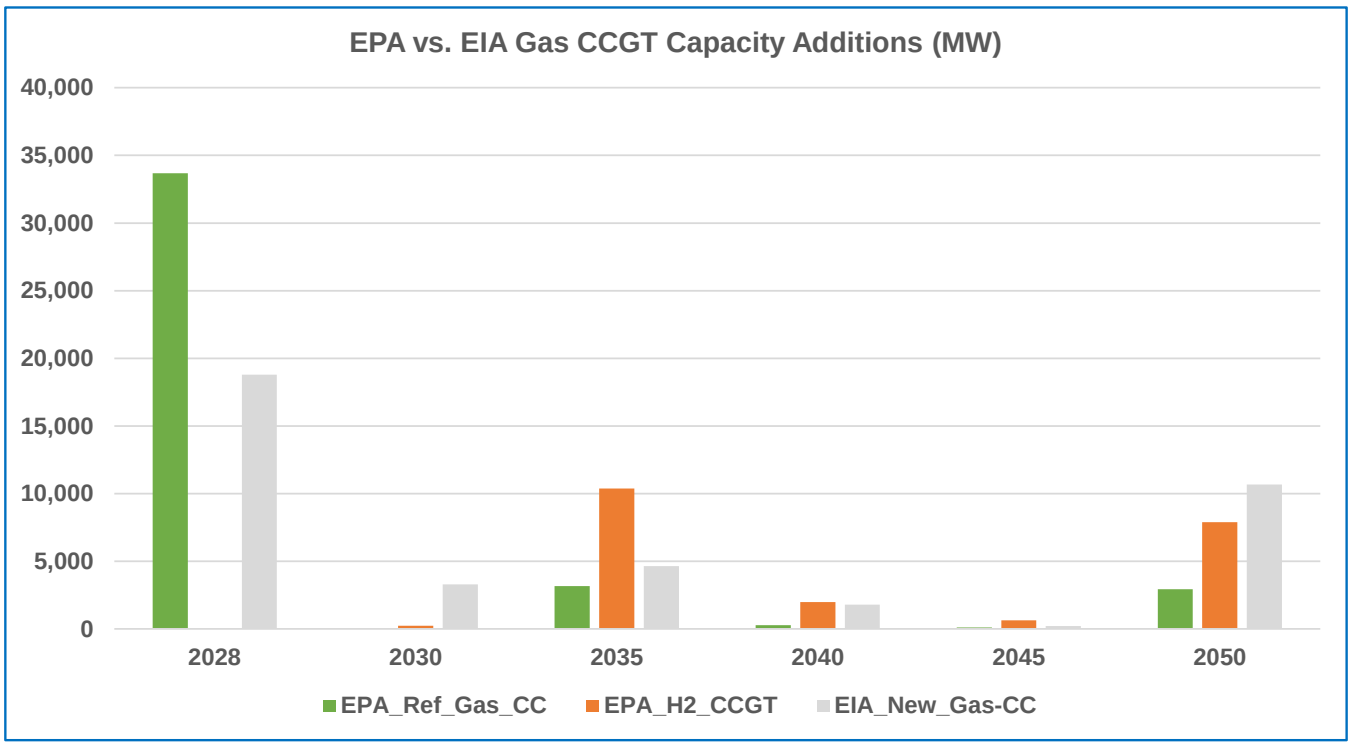
Over 2023-2028, EIA is projecting that 18,790 MW new gas-CC and 54,178 MW new gas-CT, totaling 72,968 MW will be built. Beyond 2028, EIA is projecting gas-CCGT additions ranging 20-40 GW in 5-year intervals, or annual gas additions over 2023-2050 averaging 8.1 GW per year.

A forecast comparison of EPA (CO2 Rule, Reference Case and Proposal Case) to EIA (AEO 2023 Ref Case) for new gas-CCGT and H2-CCGT generation additions (MW), in 5-year intervals, is summarized in the table and chart below.

Forecast Comarison: EPA CO2 Rule (5/11/23) vs. EIA 2023 AEO (3/17/23), Gas-CCGT Generation Additions (MW)								
	2028	2030	2035	2040	2045	2050	2023-2050	MW/Yr
EPA Reference Case								
EPA_Ref_Total_New_Gas	47,497	0	13,389	43,814	94,876	109,325	308,901	11,441
EPA_Ref_Gas_CC	33,685	0	3,167	286	116	2,939	40,193	1,489
EPA Ref_%New_Gas-CC	71%	0%	24%	1%	0%	3%	13%	13%
EPA Proposal Case								
EPA_New_Gas	51,183	123	33,734	38,979	90,133	98,518	312,669	11,580
EPA_H2_CCGT	0	233	10,382	1,997	632	7,887	21,131	1,057
EPA_%H2-CCGT	0%		31%	5%	1%	8%	7%	9%
EIA Reference Case								
EIA_New_Gas	72,968	20,542	32,323	26,860	26,291	40,906	219,890	8,144
EIA_New_Gas-CC	18,790	3,296	4,651	1,807	217	10,670	39,432	1,460
EIA_%New_Gas-CC	26%	16%	14%	7%	1%	26%	18%	18%

The table above is presented in graphic form in the two graphs below. The first graph is the total gas generation, and the second graph is the likely hydrogen fired gas generation.


EPA vs. EIA New CT Capacity Additions (MW)
120,000
100,000
80,000
60,000
40,000
20,000
0
2028
2030
2035
2040
2045
2050
EPA_Ref_Total_New_Gas
EPA_New_Gas
EIA_New_Gas


EPA vs. EIA Gas CCGT Capacity Additions (MW)
40,000
35,000
30,000
25,000
20,000
15,000
10,000
5,000
0
2028
2030
2035
2040
2045
2050
EPA_Ref_Gas_CC
EPA_H2_CCGT
EIA_New_Gas-CC

1.1.2 CONCLUSIONS REGARDING EPA FORECASTS

There are several key conclusions that can be made from the above data:

- It may be difficult to make direct a comparison of the EIA data with the EPA proposal case since the EPA proposed data case considers the EPA proposed rule. It is for these reasons that Kiewit evaluated the EPA reference case as well.
- When comparing the EPA reference case to the EIA cases, it is concerning that the EPA case has so much more total combustion turbines forecasted than the EIA. It has almost 50 percent more combustion turbines forecasted as being built between now and 2050. This is likely a result of requiring plants to operate at less than a 50% capacity factor to maintain compliance, which again causes more plants to be built, more capital to be expended, but without any net reduction in emissions.
- Compared to the EIA, the EPA's estimates for combustion turbine generation requirements appear to be underestimated, despite overestimating total combustion turbine needs. The EIA is indicating that typically between 15 and 25 percent of new gas generation is combined cycle, whereas the EPA percent is between 0 and 10 percent. The result is a significant difference in potential hydrogen needs.

Total Potential Hydrogen Needs

Forecast	Total New MWs 2028 to 2050
EPA_H2_CCGT	21,131
EIA_New_CCCT	39,432

- The EIA's model represents the industry benchmark forecasting and planning. One of its benefits is that it does a better job of accounting for demand side management than does the EPA model. Therefore, its total energy needs are more accurate starting point for this analysis than the EPA's.

1.1.3 REVIEW OF ADDITIONAL EPA MODELING

On July 7, 2023, EPA released additional modeling in support of the proposed rule. The additional modeling reflects EPA's analysis of the integrated proposal (i.e., modeling the requirements on existing combustion turbines) and the third phase after 2040 of the NSPS together with the requirements that were already modeled as part of the Regulatory Impact Analysis for this rulemaking. Additionally, the analysis also separately projects illustrative impacts of higher LNG export demand consistent with the recently released EIA annual energy outlook AEO 2023. The EPA changed assumptions for natural gas prices and LNG prices in the IPM model scenarios for the Updated Baseline scenario and the Illustrative Integrated Proposal scenario, and *"exogenously"* evaluated the potential for hydrogen co-firing in existing combustion turbines, which were not evaluated in EPA's original Proposal case. This means that they evaluated hydrogen co-firing on existing turbines *outside* of the main model. It is difficult to know what this fully means, but it does appear that the existing combustion turbines were not fully integrated into the main model.

We draw attention to the following statements from EPA's memo of July 7, 2023, with concern as stated:

- The EPA indicates that 17 GW of NGCCs and 6 GW of NGCT additions will co-fire hydrogen in 2035.
- In 2040, the EPA forecasts that 1 GW of NGCC and 6 GW of NGCT additions are projected to continue to co-fire hydrogen.
- Of the existing NGCC units greater than 300 MW, 25 GW are projected to co-fire hydrogen in 2035 and 5 GW are projected to co-fire hydrogen in 2040.

- Table 22 (Integrated Proposal with LNG Update) shows additional hydrogen co-firing of 48 GW in 2035, and 12 GW in 2040.
- There is a discrepancy in EPA's estimate of additional hydrogen co-firing (2035, 25 GW vs 48 GW) in Table 22.
- EPA did not state the percentage of hydrogen co-firing in existing gas-CC over 300 MW size assumed.
- While proposed CO2 Rule requires minimum 30% co-firing of hydrogen in 2032, most existing gas-CC over 300 MW size do not have the capability to co-fire 30% hydrogen, and EPA did not evaluate how they would be retrofitted to maintain capacity.
- The economics of retrofits to existing gas-CCs over the 300 MW size to be capable of co-firing 30% hydrogen does not appear to be evaluated in EPA's analysis.

Kiewit has the following concerns with the July 7, 2023, modeling:

- The EPA did not provide a complete set of information on the July modeling, as they did with the original modeling. As a result, it is impossible assess the validity of this additional modeling.
- The modeling was provided extremely late in the comment period and, therefore, there was not time to analyze this information appropriately. Yet, EPA is presenting it as justification along with the rest of information as equal justification.
- By the EPA's own admission, the modeling of the existing combustion turbines is not fully integrated into the rest of the model. So, as a result, it is unknown whether they are being modeled correctly or whether they are accurately interacting with the rest of the grid.
- As will be discussed further in this report, it does not appear that the EPA has accounted for the fact that units retrofitted for hydrogen firing will not be able to maintain their original capacity without significant retrofit. This is a significant economic hit to these turbines that has not been modeled.

In summary, the lateness of the EPA's additional modeling, the way it was performed (i.e., outside of the IPM model), and the fact it does not account for lost capacity, make the July 7, 2023 modeling results extremely questionable and unreliable. In Kiewit's opinion, they cannot be depended on for policy decisions.

1.1.4 EPA COMMENTS ON HYDROGEN

EPA incorrectly assumes hydrogen firing will not impact the capacity of affected units.

EPA's Resource Adequacy Analysis document incorrectly asserts that:

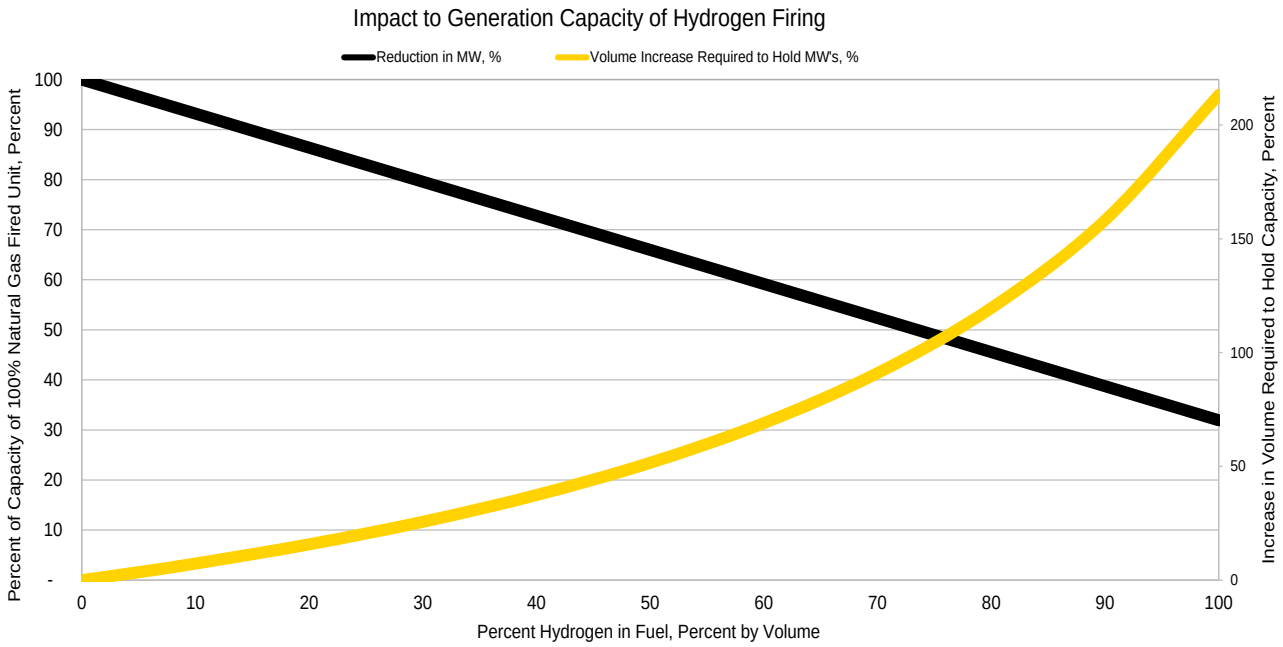
> *"For both the affected units that reduce capacity factor to 50% and those that increase hydrogen co-firing to 96% by volume, unit capacity accreditation and the amount that they contribute to resource adequacy is unchanged, as there is no capacity derate for hydrogen co firing."*

[CITE at p. 8.]

It is important to understand that capacity refers to a unit's maximum electric output, while capacity factor refers to the fraction of a unit's total available capacity utilized over a period of time. Hydrogen co-firing at 96% is likely to negatively affect a unit's capacity. That is because hydrogen has an energy density that is roughly 1/10th of natural gas. Therefore, even though the heating value of hydrogen is higher than natural gas, the increased heating value does not make up for the lower energy density. The EPA acknowledges this difference in its Technical Support Document titled "Hydrogen in Combustion Turbine Electric Generating Units" on Page 3:

> *"One of the differences between hydrogen and natural gas is the energy density by volume of the gases. To achieve significant GHG reductions from burning hydrogen in a combustion turbine, the volume of hydrogen must be high relative to the volume of natural gas."*

This difference in energy density means that for a combustion turbine to achieve the same capacity burning hydrogen as it would with natural gas, it would need to fire significantly more hydrogen. The graph below shows this impact.



The black line on the graph shows how the capacity of a unit changes as hydrogen firing is increased. For example, if hydrogen provides 70 percent of the fuel (by volume), the capacity of the unit will drop to 50% of the MW's it could produce when it was firing natural gas. When the unit is firing 96% hydrogen, it can only produce approximately 35% of the MW's that could produce when firing natural gas. So, to maintain the same MW production in a combustion turbine that is firing 96% hydrogen, a utility would have to fire almost 200% more fuel. The yellow line on the graph shows this. As such, a combustion turbine burning 96% hydrogen would have a significantly lower capacity.

To the extent that EPA is referring to capacity factor, its assertion is equally unsupported. A unit burning 96% hydrogen would have 65% less capacity than the same unit burning natural gas. For example, for a 100 MW unit firing natural gas, the same unit firing 96% hydrogen would have a capacity of 35 MW. Even if one were to assume that the unit's availability and utilization were the same (an assumption that is speculative because there is no history or data with which to assess the reliability of units burning 96% hydrogen since they do not exist), its capacity factor would be lower. That is because capacity factor is expressed as capacity in MW / utilization. And since the capacity will have decreased, so will the capacity factor.

For EPA's assertion to be true, the combustion turbine would have to burn approximately 200% more fuel to provide the same amount of power. It is unlikely that every unit can be designed or retrofitted to do so. Among other reasons, combustors would have to be converted for a much larger flow rate, which may or may not be possible. It would also require that the fuel supply system and the control system would need to be modified to handle 200% more flow, again it is unlikely to be possible on all the units where this would be needed. In addition, to our knowledge, it has not yet been attempted. The HRSG and emissions control equipment would also need to be able to handle the additional exhaust. Even if a few units could make such changes, it is unlikely that these changes will be able to be made on a consistent basis, system wide, to maintain capacity.

In short, EPA's assumption that 96% hydrogen firing will allow existing units to maintain their capacity is incorrect. Instead, the proposed rules would likely require significant additional generation to be built to make up for the loss of generating capacity because of switching to hydrogen. The EPA did not model this.

1.2 HYDROGEN IN COMBUSTION TURBINE EGUS

To support its assertion that hydrogen co-firing is ready for implementation on a large scale, EPA provides a list of new hydrogen firing projects on pages 8 and 9 of its Hydrogen in Combustion Turbine Electric Generating Units technical support document. The list fails to support EPA's conclusions.

Below is the list of projects in EPA's report, along with the total MWs and some additional comments on these projects. It should be noted that several of these projects are Kiewit projects.

Facility	Total MW[1]	Initial Hydrogen Firing	MW of Hydrogen[2]	Comments
Long Ridge Energy Center*	485	5%	24	Not green hydrogen, can only operate on hydrogen 45 minutes at a time
Intermountain Power Agency*	840	30%	250	Not yet operational
LADWP	297	30%	89	Not operational on hydrogen until 2029
Lincoln Land Energy Center	1,100	30%	~230	Not operational
Newman Power Station	178	30%	50	Not currently operational on hydrogen
Orange County Advanced Power Station*	1,215	30%	250	Design not started yet; EPA's description does not specifically indicate green hydrogen
Magnolia Power Plant*	725	50%	200	Not operational until 2025, capable of 50% H2 firing if hydrogen is available, EPA's description does not specifically indicate green hydrogen
Total	4,840		1,093	

Notes:

1. **Total MW = Total MW's that will be produced by the facility**.
2. MW of Hydrogen = Total MW's that will be produced from firing hydrogen initially (not including power from steam turbines). In all cases, 100% hydrogen firing is aspirational.
3. The (*) indicates Kiewit projects.

The only one of these units that is in operation and using hydrogen firing is the Long Ridge Energy Center. Long Ridge Energy Center's onsite storage only allows for firing up to 5% hydrogen. In addition, the facility can only fire hydrogen for 45 minutes before it runs out of storage. The other units on this list are all in the planning, design, or construction stage. None of the other units are in operation. In addition, none of these units are expected to fire anywhere close to 96% hydrogen initially. Instead, they expect to burn between 30-50% hydrogen, with an aspirational goal of having the capability of firing more.

Second, it should be noted that the timeline for most of these projects to be firing 100% hydrogen is 2045. This is significant since these units are the *early adopters*, with high aspirations for firing hydrogen. The 2045 date of these units, which the EPA presents as examples of what is possible with hydrogen firing, does not support EPA's 2038 deadline for 96% hydrogen firing.

In addition to the technical concerns discussed above, the list in the table represents an exceedingly small proportion, less than 0.1 percent, of the US combustion turbine fleet. While it may indicate that the industry is moving towards the technical ability to fire hydrogen, the EPA has not made (and cannot make) the case that the industry can meet the demands for hydrogen firing that this rule would require. Hydrogen transportation, availability, along with capability of combustion turbines all play a part in why the industry is not ready for this challenge, as will be discussed later in the report. But the timeline presented by EPA in the regulations is too aggressive.

2. HYDROGEN COMBUSTION

This section will discuss the industry status of hydrogen combustion in combustion turbines.

2.1 CAPABILITY OF COMBUSTION TURBINE OEMS

2.1.1 HYDROGEN FIRING

The capability of the turbine OEMs for hydrogen firing, as reported by the EPA, are shown in EPA's table on Page 7 of EPA's Hydrogen in Combustion Turbine Electric Generating Units technical resource document:

Manufacturer	Turbine Model/Type	Current Hydrogen Capability[1]	Future Hydrogen Capability[2]
GE Gas Power			
	Aeroderivative	85%	100%
	B/E-Class	100%	
	F-Class	100%	
	HA-Class	50%	100%
Siemens Energy			
	SGT5/6-9000HL	50%	
	SGT5/6-8000H	30%	
	SGT-700	75%	
	SGT-750	40%	
Mitsubishi Heavy Industries			
	M501GAC	30%	100%
	M501JAC	30%	100%
	M701JAC	30%	100%

[1] The actual % by volume hydrogen levels may vary based on combustion turbine model, combustion model, combustion system, and overall fuel consumption. Turbines currently co-firing greater than 30% hydrogen by volume typically utilize wet, low-emission (WLE) or diffusion flame combustors.
[2] Manufacturers are developing DLN combustor modifications for several turbine models that will allow for increased hydrogen firing while limiting emissions of NO_x. These include pre-planned small modification or retrofits kits for certain models to increase their levels of hydrogen combustion.

Figure 2: Hydrogen Capabilities in Certain Models of Combustion Turbines

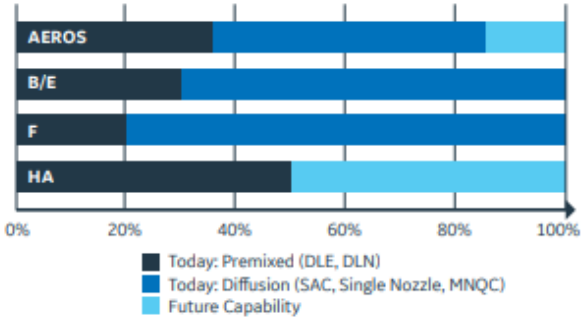
The current capability of burning hydrogen varies based on the OEM and the classification of combustion turbine. The table below is a summary of the capabilities and future target capabilities from the three (3) largest combustion turbine manufacturers from their respective websites.

Combustion Turbine Class	Current Capability	Future Capability (Target)	Expected Year for Target Hydrogen Firing
Aeroderivative	30-100% depending on OEM	100%	2025-2030
B/E Class	30-100% depending on OEM	100%	2030
F Class	20-100% depending on OEM and combustor	100%	2030

Combustion Turbine Class	Current Capability	Future Capability (Target)	Expected Year for Target Hydrogen Firing
G Class	30%	100%	2030
H Class	30-50%	100%	
J Class	30%	100%	2030

The numbers shown in EPA's table are misleading, especially for the larger frame units (F, G, H and J Class). For the GE Frame F, EPA indicates that GE can fire 100 percent hydrogen. However, GE indicates that the unit must use GE's Single Nozzle combustor (aero derivatives) or the multi-nozzle quiet combustor (frame CT's), as seen from the figure below. These combustors produce higher NOx than the dry low NOx (DLN) combustors. As of today, GE's DLN combustor can only burn between 20% and 30% hydrogen. If utilities switch away from DLN combustors to allow for more hydrogen combustion, it will increase NOx emissions from 9 ppm to 25 ppm.

Current status of GE turbines hydrogen capabilities (%vol)



Each of the three largest combustion turbine manufacturers aspire to construct 100% hydrogen fired units by 2030. However, as acknowledged by the Department of Energy National Energy Technology Laboratory's (DOE/NETL) white paper titled "A Literature Review of Hydrogen and Natural Gas Turbines: Current State of the Art with Regard to Performance and NOx Control" (https://netl.doe.gov/sites/default/files/publication/A-Literature-Review-of-Hydrogen-and-Natural-Gas-Turbines-081222.pdf); there are some major obstacles to overcome before those aspirations could be realized. Gas turbine combustors are designed to work at specific operating pressures and with a fixed volume with little room for variation. To accommodate the hydrogen fuel, the turbines will either need to be larger, use higher max pressures to reduce the hydrogen volume or both. To achieve a similar performance and emissions from a hydrogen fired turbine will cost more to produce than its natural gas fired counterpart because of the higher volumes and/or pressure requirements.

Hydrogen has a higher flame temperature, faster flame speed, and creates a higher concentration of H• radicals than natural gas, which presents some additional areas of concern for the turbine manufacturers. The higher flame temperature causes increased metal temperatures, while the higher flame speed, and particularly higher concentration of H• radicals, creates the potential for higher thermal NOx emissions and changes to thermal acoustics. These factors cause vibrations that could potentially destroy the turbine combustors. The increased metal temperatures will require localized cooling or other technique to protect parts of the turbine from thermal stresses.

One of the largest concerns with making the transition to 100% hydrogen-fired combustion turbines is the increased flame speed. Hydrogen's flame speed is an order of magnitude faster than natural gas. The higher flame speed can also increase the local flame temperature (added to the higher natural flame temperature) which accentuates the issues described above. The increased flame speed also causes concerns with flame stability within the combustion turbine. If the flame speed is higher than the fluid velocity, there will be "flashback" into the fuel mixing zone, which causes damage to the injectors and other components. If the fluid velocity is increased to avoid flashback, there is the possibility of blowout, where the flame is extinguished. This creates a challenge for

the combustion turbine manufacturers, to design the combustion system to maintain the flame stability, while also designing the turbines to handle the higher temperatures and/or pressures of the hydrogen fuel.

Regarding retrofits, as stated before in Section 1.2, there is no guarantee that the capacity of CT's will be maintained when switching to hydrogen from natural gas. With the higher flame speed and temperatures of hydrogen, retrofitting the existing combustion turbines will not be as simple as switching out the combustors. If the fuel velocity is increased to eliminate flashback, this will cause increased pressure drop across the combustor, which will have an impact on the reliability, maintenance schedule and life expectancy of the turbines.

Also of note is that the combustion turbines that can currently burn the higher percent of hydrogen are the aeroderivative and smaller combustion turbines. These smaller units are typically used as peaking units and are not typically base loaded turbines; therefore, they are not likely to be impacted by the EPA requirements. Most base load facility utilize the larger frame (F, G, H and J Class) in either simple or combined cycle configurations. The larger frame units are more efficient which makes them a better solution for base load operation.

Finally, as stated in Section 1.1.4, existing heavy duty frame gas turbines will require a new combustion and fuel system to burn the higher rates hydrogen because higher volumes of hydrogen will be required to maintain capacity. In addition, retrofit costs have not been fully assessed for converting to hydrogen, nor has the downtime required to make the conversion.

2.1.2 AMMONIA FIRING

For ammonia firing, the following information has been provided by the OEM's.

Combustion OEM	Class Size	Current Capability	Future Capability
Mitsubishi	Smaller Frame Sizes Larger Frame Size	None None	100% Planned by 2026 None
GE	6F, 7F	None	100% by 2030

EPA's proposal is unclear as to whether the agency intends to allow ammonia firing as a form of hydrogen firing. However, ammonia firing information is being presented here because there would be some advantages to being able to fire ammonia instead of hydrogen. Those advantages have to do with transportation and storage infrastructure. Ammonia is already a common commodity in the US because it is used for fertilizer. The regulations for storage and transport are well established and it is much more commonly transported than hydrogen. However, as can be seen by the table above, there is limited effort being made by the OEMs to develop ammonia firing capability. Therefore, ammonia is unlikely to significantly change the US's ability to implement widespread hydrogen firing.

2.2 OPERATING IMPACTS OF FIRING HYDROGEN

Within each combustion turbine class, there are different turbines each with different current capabilities for burning hydrogen. Using the current hydrogen capability of each turbine we calculated how much hydrogen (kg) each turbine can burn currently and divided that by the output of the combustion turbine to get the amount of hydrogen required per megawatt of power. Below is a table which shows the hydrogen required to generate 1 MW of power output for each of the turbine classes averaged across all the combustion turbine OEMs. The table also shows how much hydrogen would be required in each of the turbine classes to burn 100% hydrogen, again averaged across each of the OEMs. Using electrolysis to create hydrogen requires both demineralized water and auxiliary power. Electrolysis is the process of splitting water into hydrogen and oxygen using electricity. The demineralized water and auxiliary power required shown below is based on using Proton Exchange Membrane (PEM) electrolysis for generating hydrogen and is representative of various electrolyzer OEMs.

Turbine Class	Output Range	Hydrogen Req'd Current Capability	Hydrogen Req'd Future Capability	Demin Water Req'd Current Capability	Demin Water Req'd Future Capability	Aux Power Req'd Current Capability	Aux Power Req'd Future Capability
Units	(MW)	(kg/MW)	(kg/MW)	(gal/MW)	(gal/MW)	(MW/MW)	(MW/MW)
Aeroderivative	5-65	14	25	0.66	1.18	0.764	1.364
B/E Class	75-120	15	25	0.71	1.18	0.819	1.364
F Class	170-250	7	23	0.33	1.09	0.382	1.255
G Class	225-285	7	22	0.33	1.04	0.382	1.201
H Class	275-390	9	21	0.43	0.99	0.491	1.146
J Class	330-430	6	20	0.28	0.95	0.327	1.091

As shown from the table above, the amount of hydrogen required per MW is larger for the smaller combustion turbines. These turbines are less efficient and require more fuel per MW than the larger turbines. The table also shows that for all combustion turbine classes, **the auxiliary power required to create hydrogen using PEM electrolysis is greater than the power generated by burning 100 percent hydrogen in a combustion turbine.** Such basic energy balance shows that firing hydrogen in combustion turbines is a net energy loser rather than a net energy producer. It is neither possible nor practical to require more auxiliary power than the power generated by the combustion turbine, this would create a significant reduction in energy capacity in the grid, thus resulting in a significant increase in overall construction, which defeats the overall goal of reducing greenhouse gases.

2.3 ONSITE STORAGE REQUIREMENTS

The hydrogen required for each turbine classification in the table above were used to calculate the hydrogen storage required and is shown below for both 1- and 5-days storage. The storage criteria is consistent with the current storage philosophy used at power generating facilities. The table below shows how much hydrogen would need to be stored to meet the current hydrogen capability as well as the future target capability of 100% hydrogen. The values shown below are based on a single MW output for each of the turbine classification ranges. The storage pressure of hydrogen is assumed to be 2,500 psi. When calculating how much hydrogen needs to be stored the assumption is that no onsite compressors will be used to send hydrogen from the storage to the combustion turbines which means there will always be a certain amount of hydrogen in the storage. Using the turbine gas supply pressure requirement and accounting for pressure losses between the onsite storage and the combustion turbines shows that you need to store ~32% more hydrogen than the turbine requires. The values below show how much hydrogen needs to be stored to generate the power output shown.

Turbine Class	Output (MW)	Current Hydrogen Capability Stored (1 Day) (kg)	Future Hydrogen Capability Stored (1 Day) (kg)	Current Hydrogen Capability Stored (5 Day) (kg)	Future Hydrogen Capability Stored (5 Day) (kg)
Aeroderivative	65	28,829	51,480	144,144	257,400
B/E Class	120	57,024	95,040	285,120	475,200
F Class	250	55,440	182,160	277,200	910,800
G Class	285	63,202	198,634	316,008	993,168
H Class	390	111,197	259,459	555,984	1,297,296
J Class	430	81,734	272,448	408,672	1,362,240

Based on the storage requirements in the above table, onsite, above ground storage would be as shown in the table below. There are options for underground storage of hydrogen, but those are currently limited to salt caverns which are not widely available throughout the US. Accordingly, aboveground storage was assumed for this evaluation because that would be available at more power generation facilities than underground salt caverns.

Turbine Class	Output (MW)	Number of Tanks (1 Day) Current/Future	Number of Tank (5 Days) Current/Future	Truck Deliveries to Fill the Tank (1 Day of Storage) Current/Future	Truck Deliveries to Fill the Tank (5 Day of Storage) Current/Future
Aeroderivative	65	16 / 28	77 / 138	46 / 83	233 / 416
B/E Class	120	31 / 52	153 / 255	92 / 153	460 / 767
F Class	250	30 / 98	149 / 489	89 / 294	448 / 1,470
G Class	285	34 / 107	170 / 533	102 / 320	510 / 1,602
H Class	390	60 / 140	298 / 696	179 / 418	897 / 2,093
J Class	430	44 / 147	219 / 731	132 / 439	660 / 2,198

Note:
Truck delivery assumes all truck deliver in a 12-hour period. Each truck delivery contains 310 kg. Each tank holds 1,863 kg.

Most facilities store backup fuel supplies (1 to 5 days) on site to guard against infrastructure and transportation disruptions. Accordingly, it is reasonable to assume that they would similarly do so with hydrogen, especially because of the high degree of uncertainty and unknowns surrounding the current and future hydrogen infrastructure. Even with only 1 day of hydrogen storage onsite, a generating facility would be significantly hampered in its ability to continue generating power during supply disruptions.

Each tank would require approximately 1,500 ft^2 of land. For 1 day of storage for an H-Class turbine requiring 140 aboveground tanks that would require approximately four acres of storage tanks. If 5 days of storage was used for the H-Class turbine that would be approximately 17 acres for the storage tanks. The required storage area will be a concern for many existing facilities. There will also be safety and fire protection implications for storing this amount of hydrogen aboveground, including zoning restrictions.

The tables above show that truck delivery and storage of even a small amount of hydrogen onsite is not practical. For an F-Class turbine, the facility would need to receive 294 trucks in a 12-hour period to maintain the 1-day storage. To do that, each truck would need to unload in less than 2.5 minutes; For H-Class turbines that would have to be done in 2 minutes. It is not possible to have trucks pull into site and unload in less than 3 minutes.

A more realistic duration for truck deliveries would be 30-60 minutes for each truck. With the trucks being unloaded 12 hours per day, it would take between 12 and 24 days to unload the number of trucks for a single F-Class turbine to provide 1 day of hydrogen storage. It would take between 17 and 35 days of truck deliveries for a single H-Class turbine and 1 day of storage. Many existing power generation facilities have multiple combustion turbines on their site, which would cause even longer durations and larger tanks requirements on the site.

Even if a facility could be designed to include the number of tanks required in the tables above, additional infrastructure would be required to upgrade the roads to the plant to be able to handle hydrogen tanker trucks arriving to and leaving from the plant every 2 minutes. These roads would have to be designed all over the country for the same situation, as hydrogen would be delivered to many facilities throughout the U.S. In addition, the delivery travel from the hydrogen production facilities to these power plants would place a lot of wear and tear on road.

2.4 IMPACT ON NO_X EMISSIONS

One of the potential environmental impacts of firing hydrogen is the potential increase in NOx emissions. As stated on Page 4 and 5 of the EPA's Technical Support Document titled "Hydrogen in Combustion Turbine Electric Generating Units":

> *"The technical challenges of co-firing hydrogen in a combustion turbine EGU result from the physical characteristics of the gas. Perhaps the most significant challenge is that the flame speed of hydrogen gas is an order of magnitude higher than that of methane; at hydrogen blends of 70 percent or greater, the flame speed is essentially tripled compared to pure natural gas.12 A higher flame speed can lead to localized higher temperatures, which can increase thermal stress on the turbine's components as well as increase thermal NOx emissions. It is necessary in combustion for the working fluid flow rate to move faster than the rate of combustion. When the combustion speed is faster than the working fluid, a phenomenon known as "flashback" occurs, which can damage injectors or other components and lead to upstream complications.*
>
> *Other differences include a hotter hydrogen flame (4,089 °F) compared to a natural gas flame (3,565 °F) and a wider flammability range for hydrogen than natural gas.16 It is also important that hydrogen and natural gas are adequately mixed to avoid temperature hotspots, which can also lead to formation of greater volumes of NOx.*
>
> *Combustor modifications or retrofits have the potential to limit NOx emissions. For example, a larger selective catalytic reduction (SCR) unit inside the heat recovery steam generator (HRSG) is an option for combined cycle turbines. For combined cycle plants planning to co-fire higher volumes of hydrogen over time, it is important to estimate the increased NOx emissions when sizing the SCR unit."*

The EPA has therefore acknowledged that NOx will go up in many cases for combustion turbines firing hydrogen. While the combustion turbine OEMs have not yet expressed significant concerns with increased NOx emissions at the 30% hydrogen firing case, there is no testing data available to show that NOx emissions will not be a problem. Especially in the case of retrofitting existing combustion turbines, where the OEMs will have less flexibility to make changes, the potential for increasing NOx emissions is higher, even at 30% hydrogen firing.

In addition, while the OEMs are working to produce dry low NOx (DLN) hydrogen combustors that can maintain lower NOx emissions in the future, it is uncertain whether they will be successful at maintaining the levels that are currently achievable. As with the 30% hydrogen firing case, the OEMs' ability to keep NOx low is most limited for the combustion turbines that are retrofitted to fire hydrogen.

Finally, as discussed in detail above in Section 1.1.5, when a unit fires 96% hydrogen, it will need to fire almost 200% more fuel to maintain the same capacity. A combustion turbine firing more fuel will also produce more NOx emissions because of the increase in the fuel being fired. So, hydrogen firing is potentially a double hit on NOx emissions: 1) because it results in a higher concentration of NOx emissions and 2) because the mass of emissions is higher due to more fuel being used.

3. HYDROGEN STORAGE AND TRANSPORT

3.1 HYDROGEN HUBS

It is believed that approximately 20 hydrogen hubs in the US submitted final applications by April 7, 2023 deadline to the US Department of Energy (DOE) for "regional clean hydrogen hubs" funding up to $1.25 billion (out of total of $7 billion) available for an expected 6-10 clean hydrogen hubs that will be awarded by 2030. Concept papers for the Hubs were due on November 7, 2022, and full applications were due on April 7, 2023

The ultimate winners of the DOE hydrogen hub funding selection process may not be known for some time. According to the DOE's funding opportunity announcement, the application period that concluded on April 7 leads into the first phase of the selection process, in which the DOE will dole out up to $20 million to hubs with a 50% minimum cost matching requirement following the merit review process. That phase will span 12 to 18 months during 2023-2024.

Then, awardees move into a "negotiated go/no-go" process in 2024 before moving into phase two, where they can receive up to 15% of each hub's total requested amount. This phase can take up to 2-3 three years by 2026-2027.

Once in phase three by 2027, the DOE will begin releasing the remaining 85% of federal funding on an undefined schedule while closely monitoring each hub's implementation process -- a stage that could take 2-4 years by 2029-2031. In the final fourth stage, hubs will transition to their operational stage after 2031.

It should be noted that the other side of this equation is the "Regional Clean Hydrogen Hubs Demand-side Support Notice of Intent." Responses were due by July 24, 2023. This is where parties interested in receiving hydrogen from the hubs are requested to provide notice to the DOE. This timeline is vastly out of step with the timeline for the GHG rule that the EPA has established. As defined in Section 2.3, combustion turbine units that are firing 30% or 96% hydrogen are not going to be able to have a lot of onsite storage of hydrogen because hydrogen has such a low density that makes onsite storage impractical. As a result, utilities will need to depend on hydrogen transport through pipelines for hydrogen supply. Therefore, the infrastructure created by these future hydrogen hubs will represent most of the US supply storage for hydrogen for the foreseeable future. Unfortunately, because of the 2035 and 2038 timelines in the EPA's rule, utilities will have already missed their deadline to notify the DOE of their interest in reserving supply in the hydrogen hubs. As a result, there is no guarantee that the hubs will be sized to meet the hydrogen needs of combustion turbines built or retrofitted to meet the EPA rule. Currently, there is no hydrogen fuel storage constructed to supply the needs for the combustion turbine fleet and no pipelines available for transportation.

3.2 HYDROGEN PIPELINES

As stated previously, to supply hydrogen to combustion turbine units firing hydrogen, most of the hydrogen will need to come from hydrogen hubs because onsite storage is impractical. However, there are many concerns with conveying hydrogen in pipelines. As EPA has acknowledged:

> *"Hydrogen blends of up to 5 percent in the natural gas stream are generally safe. However, blending more hydrogen in gas pipelines overall results in a greater chance of pipeline leaks and the embrittlement of steel pipelines.*
>
> *Hydrogen blends of more than 20 percent present a higher likelihood of permeating plastic pipes, which can increase the risk of gas ignition outside the pipeline.*
>
> *Analysts assert that 20 percent hydrogen concentrations by volume may be the maximum blend before significant pipeline upgrades are required. Other recent analyses of existing pipeline materials indicate that 12 percent may be the maximum blend. In addition, the existing end-use equipment in power plants and industrial facilities may not tolerate higher hydrogen concentrations without modification. If implemented with relatively low concentrations, less than 5 to 15 percent hydrogen by volume, this*

strategy of storing and delivering low-GHG hydrogen to markets appears to be viable without significantly increasing risks associated with utilization of the gas blend in most end-use devices, overall public safety, or the durability and integrity of the existing natural gas pipeline network. However, the appropriate blend concentration may vary significantly between pipeline network systems and natural gas compositions and must therefore be assessed on a case-by-case basis."

Indeed, these concerns are well documented in other sources, such as:

- "Once hydrogen enters pipelines, it can weaken metal pipes which can lead to cracking. Hydrogen is also far more explosive than natural gas which could create safety issues." – *"Focus: Has green hydrogen sprung a leak?,"* By Sarah Mcfarlane and Ron Bousso, December 22, 2022
- "It is well known that the presence of hydrogen increases fatigue crack growth rates in commonly used pipeline steels, and studies have shown that metals with higher tensile strength tend to experience greater reductions in fracture resistance than metals with lower tensile strength when in contact with hydrogen. Recent research has shown that fatigue crack growth and fracture resistance can degrade even with low partial pressures of hydrogen, with subsequent degradation being more modest as the partial pressure is increased. In high-stress situations, fatigue crack growth is fairly independent of hydrogen concentration." – *"Hydrogen Blending into Natural Gas Pipeline Infrastructure: Review of the State of Technology,"* National Renewable Energy Laboratory, University of Colorado Boulder, Sandia National Laboratories, Pacific Northwest National Laboratory, October 2022

The potential for pipeline leaks is of significant concern because these pipelines will need to be routed in areas where the public lives and works, resulting in potential hazards associated with gas ignition in populated areas.

The potential for embrittlement of pipeline material is a well-known phenomenon with hydrogen. This increases the potential for leaks. In addition, embrittlement increases the maintenance potential and inspection requirements on the pipeline. Given the quantity of pipelines that will be required to supply hydrogen to hydrogen-fired combustion turbines throughout the country, the inspection and maintenance requirements will become challenging, especially in populated areas.

Finally, these quotes establish that transporting 96% to 100% hydrogen is especially challenging. Yet, to meet the proposed requirements, the hydrogen transport piping will need to be able to transport this high concentration of hydrogen to supply 96% fired combustion turbines. The EPA's discussion of pipelines does not address the significant challenges of this transport piping at all.

In addition to the above discussions about the technical challenges with hydrogen transport piping, the EPA acknowledges the cost challenges associated with hydrogen transport piping:

"The capital costs of new pipeline construction constitute a barrier to expanding hydrogen pipeline delivery infrastructure."

As such, the hydrogen supply will be hindered by the cost of transporting the hydrogen. It is simply not practical to resolve such costly technical, engineering, let alone complete construction of an entirely new nationwide pipeline system in the timeframe and cost estimates assumed by EPA. In addition, unlike hydrogen used for transport vehicles or for shipment overseas, combustion turbines firing hydrogen need to be located in a distributed manner to meet power delivery requirements. As a result, expansive hydrogen pipeline infrastructure will be essential to the feasibility of hydrogen firing for power productions.

3.3 QUANTITY REQUIREMENTS

On Page 25 of the Technology Support Document ""Hydrogen in Combustion Turbine Electric Generating Units", the EPA indicates that "approximately 1,600 miles of dedicated hydrogen pipelines are deployed in regions of the U.S." According to the Congressional Research Service Report, "Pipeline Transportation of Hydrogen: Regulation, Research, and Policy," published March 2, 2021, 90% of that pipeline is located along the Gulf Coal in Texas, Louisiana, and Alabama. "By comparison, there are over 300,000 miles of U.S. natural gas transmission pipeline (not counting distribution mains) located in the 48 contiguous states and Alaska." From a comparison

perspective, this means there are almost 200 times more miles of natural gas pipelines in the country than hydrogen pipeline. This comparison is important because it demonstrates the infrastructure needed for natural gas to be a critical part of the US's energy supply and gives an indication of the magnitude of need for hydrogen supply pipelines. To meet EPA's goals a pipeline network close to the size of the existing (and expanding) natural gas pipeline network would need to be constructed on a timeline never before seen.

This is not speculation. According to EIA, through 2021 there were over 800 combustion turbines, in 47 states, in the US being used for power production. This demonstrates that the use of combustion turbines for power is widely distributed throughout the US. In addition, as stated previously, hydrogen supply cannot be provided by onsite storage since that is unpractical. Therefore, hydrogen supply to support hydrogen firing will need to be provided through hydrogen pipelines.

The hydrogen pipeline must reach more areas than just the current 1,600 miles along the Gulf coast and must have a reach that is much more like the 300,000 miles of natural gas pipelines that the country currently has to support combustion turbines spread through the country. In fact, while Kiewit has not calculated the exact need, the need is several orders of magnitude greater than the current pipelines available. Much of this pipeline will need to be routed in highly populated areas. Given the safety concerns discussed in Section 3.2, the issue of supply pipelines is a significant barrier to the practicality of the hydrogen requirements of the proposed rule.

4. HYDROGEN PRODUCTION

4.1 ELECTROLYZER OEMS

Electrolyzer manufacturers offering their products in the US consist of industrial conglomerates with an electrolyzer division such as Siemens, mature “pure play” manufacturers such as Plug Power and new start-ups with a successful lab experiment. Offerings vary from stack-only to complete plug and play packages.

We have identified twelve (12) manufacturers currently active in the US market. While this list is not exhaustive, it includes the majority of the players in the U.S. market. The different electrolyzer technologies are described below:

AEM – Anion Exchange Membrane

AWE – Alkaline Water Electrolysis

E-TAC – Electrochemical, Thermally Activated Chemical

PEM – Proton Exchange Membrane

SOEC – Solid Oxide Electrolyzer

In the table below, “capacity” indicates the amount of power required by the electrolyzer to produce hydrogen. This is the typical convention used when defining the size of electrolyzer capacity. The manufacturers in the table below have a combined 2023 capacity of approximately 12 GW of hydrogen production. Since every GW of electrolyzer capacity can produce an estimate 400 tons per day of hydrogen, this represents 4,800 tons per day of hydrogen production for 2023. **If all the electrolyzers forecasted for 2023 were built to produce hydrogen for combustion turbines, the forecasted hydrogen production for 2023 would provide enough hydrogen to fuel approximately 87 F-Class or 43 H-Class combustion turbines burning 100% hydrogen for just 1 day.**

COMPANY	TECHNOLOGY	YEAR OF EXPERIENCE[1]	BNEF 2023 FORECAST MFG CAPACITY (MW)	MARKET CAP[2] (MILLIONS)	2022 REVENUE (MILLIONS)	2022 NET INCOME (MILLIONS)
Bloom	SOEC	22	2000	$4,150	$1,199	($301)
Accelera (Cummins)	PEM, AWE	70+[3]	1600	$34,190	$28,074	$2,151
Enapter[4]	AEM	6	280	$344	$13,924	($10,291)
H2Pro	E-TAC	4	No Forecast	Private[5]	Unknown	Unknown
H-TEC[6]	PEM	26	0	$16,597	$138,009	$6,000
Hydrogen Optimized[7]	AWE	6[8]	No Forecast	Private	Unknown	Unknown
NEL	PEM, AWE	96	500	$2,330	$96	($122)
Ohmium	PEM	4	2000	Private[9]	Unknown	Unknown

COMPANY	TECHNOLOGY	YEAR OF EXPERIENCE[1]	BNEF 2023 FORECAST MFG CAPACITY (MW)	MARKET CAP[2] (MILLIONS)	2022 REVENUE (MILLIONS)	2022 NET INCOME (MILLIONS)
Plug	PEM	26	3000	$7,330	$701	($274)
Siemens	PEM	TBD	1300	$125,030	$78,028	$4,036
Sunfire[10]	AWE, SOEC	13	500	Private	Unknown	Unknown
ThyssenKrupp	AWE	100[11]	1500	$4,600	$43,336	`

1. Measured from date of incorporation.
2. As of 10 March 2023, PER S&P Global Intelligence
3. Includes Stuart Energy experience.
4. 2021 results
5. Has publicly announced 4 rounds of funding, most recent in January 2022, totaling ~$97m.
6. Owned by MAN Energy Solutions SE, a wholly owned subsidiary of Porsche Automobil Holding SE. Revenue and income 2022 forecasts for ultimate parent, Porsche.
7. Hydrogen Optimized technology is basically AWE, however they have a unique electrode arrangement that has not been deployed on a large scale.
8. The founders of Hydrogen Optimized, the Stuart family, has electrolysis experience of more than 100 years.
9. Series B funding round completed April 2022. Raised $45m, estimated valuation of $135m.
10. Has publicly announced 6 rounds of funding, most recent in July 2022, totaling ~$262m, with last available valuation of $1.7B. Revenue and net income from 2020.
11. Includes experience of De Nora

It should be noted that the above listed forecasted capacities are the nameplate capacities of the electrolyzer. If renewable energy is utilized as the power source for the electrolyzer, the actual output will be lower. The capacity factor, or amount of time energy is produced, for renewables is approximately 30%. So, the actual production of hydrogen could be 30% of the above listed values. Using the forecast data presented in Section 1.1.4, the hydrogen required is as follows:

Total Potential Hydrogen Needs for New Units

Forecast	Total New MWs 2028 to 2050	Hydrogen Needs, tons per day
EPA_H2_CCGT	21,131	14,000
EIA_New_CCCT	39,432	26,233

This does not include any other uses for electrolyzers, including international uses and other US uses. It also does not include any existing combustion turbine facilities that will require hydrogen retrofits. This indicates that a significant increase in electrolysis project manufacturing and execution would be required to meet the hydrogen needs required by the EPA. Bottom line, the electrolyzer industry is simply not suitable to meet the demand that would be put on the industry if EPA's rule is passed.

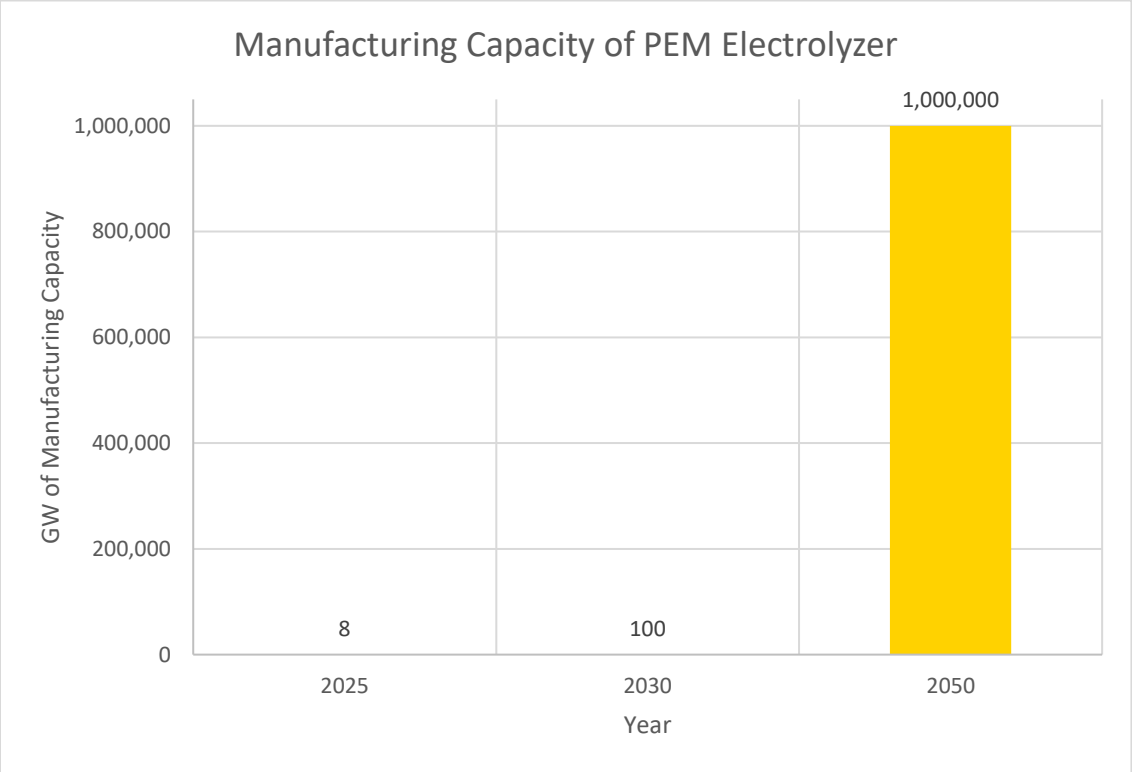
4.2 ELECTROLYZER PRECIOUS METALS

In addition to the electrolyzer production not being able to support the demand from EPA's rule, the precious metals, especially iridium and platinum, needed to produce electrolyzers are a critical barrier to production.

PEM electrolysis is the most popular technology, and it uses iridium and platinum. According to an article published by the International Renewable Energy Agency (IRENA) https://www.irena.org/-/media/Files/IRENA/Agency/Publication/2020/Nov/IRENA_Green_Hydrogen_breakthrough_2021.pdf?la=en&hash

=40FA5B8AD7AB1666EECBDE30EF458C45EE5A0AA6, scarce materials can represent a barrier to electrolyzer cost and scale-up.

The current production of iridium and platinum for PEM electrolyzer will only support an estimated 7.5 GW of annual manufacturing capacity. However, IRENA estimates that demand will require an annual manufacturing requirement of 100 GW by 2030. IRENA also projects that 1 TW of installed capacity would be required in 2050. The graph below demonstrates these numbers if visual form and shows the impractical requirements for iridium and platinum if IRENA's forecasts are correct. However, even if IRENA's forecasts are close, it demonstrates a significant problem in the commodities market with meeting the needs of the electrolyzer market for green hydrogen.



The bottom line for electrolyzers is that the demand for them in the next two decades is exponential. However, the precious metals availability means meeting these goals are highly unlikely. Given these facts, EPA's assumption that hydrogen can be produced by electrolysis, in the quantities that will be required to by the rule, is flawed.

Attachment J

Analysis of Hydrogen in Combustion Turbine Electric Generating Units

Regarding: EPA's Proposal 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"
(Docket EPA-HQ-OAR-2023-0072)

Prepared for the National Rural Electric Cooperative Association By:
Mr. Doug Campbell, FTB Energy Solutions, Inc.

August 3, 2023

Introduction

This paper provides technical commentary on the Environmental Protection Agency's (EPA's) proposed rule "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." The proposed rule would require some fossil fuel-fired stationary combustion turbine electric generating units (EGUs) to use emission control measures that are based on highly efficient generating practices, hydrogen co-firing, and carbon capture and storage (CCS). [1]

Executive Summary

This document focuses on various aspects of hydrogen co-firing, including known demonstrations to date, status of hydrogen production and transportation, and numerous identified technology challenges. The EPA's stated objective is "each of the [New Source Performance Standards (NSPS)] and emission guidelines proposed here would ensure that EGUs reduce their [greenhouse gas (GHG)] emissions in a manner that is cost-effective and improves the emissions performance of the sources, consistent with the applicable [Clean Air Act (CAA)] requirements and caselaw."

This paper only looks at the evaluation of the status of the technology as presented in "Hydrogen in Combustion Turbine Electric Generating Units Technical Support Document." [2] This paper does not evaluate the proposal's consideration of CCS for gas-fired units.

The following key findings were determined:

1) Approximately 176 MW of clean energy is required to produce enough green hydrogen to generate 46.6 MW of electricity, firing in a gas turbine at 100% hydrogen. This is extremely inefficient and would result in the addition of a significant amount of electrical generation required to create the hydrogen fuel.
2) The only available transport currently being used to get hydrogen to test sites is tube trailer trucks. To run one LM6000 at full load (approximately 45 MW) for 24 hours would require more than 200 trailer truckloads to be delivered and unloaded in that period. The amount of GHG emissions from the transportation of the fuel would be significant and would undercut any perceived benefit derived. (The LM6000 is one of the more common gas turbines in the generation fleet and has a full load rating at sea level standard conditions of 46.6 MW.)
3) Although hydrogen can be transported in specially built pipelines, there is not currently a sufficient piping network available, nor will there be in the foreseeable future.
4) A hydrogen production price of $0.5/kg or $1/kg, as referenced by EPA, is based solely on the Department of Energy's goals. [3] This is significantly lower than the current estimated cost of $5/kg of hydrogen produced by electrolysis and significantly lower than even the International Energy Agency's most optimistic projections of future hydrogen costs.

Background

For the purposes of the EPA's proposal, **"**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,**"** [1] affected gas units are categorized in Table 2 (Proposed Sales Thresholds for Subcategories of Combustion Turbine EGUs) of page 33322 of the proposed rules as either new gas combustion units or existing gas combustion units. New gas combustion units (i.e., those that commenced construction on or after May 23, 2023) would need to meet certain emissions limitations, clean hydrogen co-firing requirements, and/or CCS requirements. The compliance requirements for new gas units depends upon their capacity factor categorization as either baseload units (generally above 40% for simple cycle units or above 55% for natural gas combined cycle (NGCC)), intermediate load units (between 20% and 40% for simple cycle or 55% for NGCC), or low load units (less than or equal to 20%). For existing gas combustion units, large units with a nameplate capacity of greater than 300 MW and a capacity factor of greater than 50% would be required to meet either clean hydrogen co-firing requirements or CCS requirements.

The EPA has modelled its assumptions using the Integrated Planning Model (IPM) v6.21 model, [4] using assumptions of cost data, such as the National Energy Technology Laboratory (NETL), the International Energy Administration (IEA) Energy Outlook, and other industry reports. The classifications for this model are as defined in Table 2 on page 4 of the "Integrated Proposal Modeling and Updated Baseline Analysis." [5] It appears that the EPA has grouped multiple years in each run, with a total of four runs. Although selective output is presented in the reports, there does not appear to be sensitivity runs on the variables that would be considered most important, other than gas supply curves. Other variables might be just as important for modeling, such as demand, dry or wet hydropower years, or oil prices. This generally would be determined by a presentation of the statistical relevance of each factor. The EPA does say run time was a consideration in making these choices, but provides no insight as to the boundaries. Furthermore, there appears to be no consistency in batching the years run. All this is important because big swings in major variables can change dispatch significantly. By running sensitivities, risk exposure can be defined.

Analysis and Considerations

The information reviewed in this section is found in the EPA's document "Hydrogen in Combustion Turbine Electric Generating Units Technical Support Document," Docket ID No. EPA- HQ- OAR-2023-0072. [2] The EPA uses NETL cost data that is developed through a well-defined procedure described in NETL document "Quality Guidelines for Energy Systems Studies," [6] using Class 4 or Class 5 estimates. It is noted that these guidelines are consistent and widely accepted in cost comparisons of one technology to another, but they do not provide a comprehensive assessment of total project costs. As the owner is exposed to full project cost, for such a comprehensive assessment, a full project cost approach should be used, as referenced in the U.S. Energy Information Administration's (EIA) "Capital Cost and Performance Characteristic Estimates for Utility Scale Electric Power Generating Technologies" report. [7] That approach better demonstrates the cost for specific projects. Further details on the analysis

supporting this recommendation can be found in the accompanying comment paper, "Analysis of the National Energy Technology Laboratory Cost Estimation Guidelines and Comparison with Alternate Estimate from the Energy Information Administration, Sargent & Lundy," (Doug Campbell, August 3, 2023).

Hydrogen Production

The EPA document states that "most of the dedicated hydrogen currently produced in the U.S. (more than 95 percent) originates from natural gas using a process known as steam methane reforming." The paper then goes on to discuss various other processes for hydrogen production that are at different stages in development. The target date for new and existing natural gas units of 30% co-firing with low-GHG hydrogen is 2032.

By the definition of low-GHG hydrogen, this energy would have to come from renewable energy resources, such as wind or solar. In reviewing estimated timelines for permitting, licensing, and construction of new zero-emitting nuclear generating facilities, such as small modular reactors, it is unlikely that this would be a viable option for hydrogen production in the timeframe required. When considering small modular reactors, it is noted that the process of mining and refining uranium ore requires large amounts of energy that generally come from CO_2 emitting resources.

The only technology that appears to be viable at scale in the time frame that would meet EPA's low-GHG requirements is hydrogen produced by electrolysis. Electrolysis is a process that uses the power of electricity to split elements into compounds. In this process, electric current is passed between a cathode and an anode in water to release hydrogen and oxygen. Electrolysis is forecast to require between 48-53 kWh of electricity to produce one kilogram of hydrogen. [8] The energy required to produce enough hydrogen to fire one single LM6000 simple cycle gas turbine (46.6 MW gross) is calculated to be 176.5 MW or 3.8 times the output power. This calculation assumes a rating of 46.6 MW gross for the LM6000. Gross power is the total power generated by the unit including the power required to supply auxiliary equipment. Net power to the system is gross power minus auxiliary power.

Important to the EPA analysis is the cost of hydrogen. The second phase of the proposed regulation starts in 2032, and the EPA states in the notes of page 4 of the reference document [5] "delivered hydrogen price is assumed to be $0.5/kg in years in which the second phase or third phase of the NSPS is active, and $1/kg in all other years." Cost studies that I have reviewed show that the most optimistic price being used today is about $5/kg using electrolysis. The IEA Global Hydrogen Review 2022 [9] page 6 shows the cost range of clean hydrogen, even under an optimistic scenario, would still fall between $1.3/kg and $4.5/kg by 2030. This optimistic scenario assumes electrolyser projects currently under development are completed, manufacturing capacities are rapidly scaled up, and the costs of renewable energy continues to drop.

The lower end of that range would only be possible for regions with sufficient access to renewable energy to be competitive. A median price of $2.9/kg, based on that IEA projection, could reflect a 40% reduction in the cost of low-GHG hydrogen, but would still be six times greater than the EPA's modelled price. This is a major concern.

The EPA also notes on page 20 of the reference document that "for each kg of hydrogen produced through electrolysis, 9 kg of by-product oxygen are also produced and 9 kg of purified water are consumed." [2]. To create enough fuel to run a single LM6000 for 24 hours at 46.6 MW gross on 100% hydrogen, one would use 173,142 U.S. gallons of water per day just to make hydrogen. Any additional water requirements to run the unit would be added to this. In many regions of North America, water resources are at a premium now and would not be able to support these levels of low-GHG hydrogen production, so this provides another challenge to the hydrogen supply.

Use of Hydrogen in Combustion Turbines

It is recognized that combustion turbines have been burning by-product fuels containing hydrogen for decades. It is noted in the EPA documents that these applications are generally in the oil and gas sectors, as well as some developments with syngas firing for Integrated Gas Combined Cycle (IGCC) units. The discussion that is presented in the Technical Support Document references a long list of original equipment manufacturers' (OEMs') marketing material related to hydrogen co-firing from major manufactures such as GE, Siemens, and Mitsubishi. After reviewing several of these documents, my determination is that they are presented as either design goals for potential modification for existing units or development goals for futures offerings. Therefore, sales information that market blends beyond 20% have not been demonstrated in field tests with publicly available data. Until these units are proven commercial, they are not available to meet the EPA standards. The EPA is instead assuming that all the proposed test work will result in commercially-proven offerings.

The document also provides a list of proposed projects with specified hydrogen blends of 30% by volume and have projected completion dates between 2025 and 2029. Other projects are also described as "hydrogen ready," but there is no detailed information on what that means. As far as can be determined from literature searches, these projects are still in either the pre-Front-End Engineering Design (FEED) or FEED process of design and characterization and have not yet been determined to be economical or feasible. In some cases, permits have been obtained, but no firm operational dates are available. Based on publicly available information, these are only on paper or could be test runs in OEM research facilities. An example project that the EPA uses is the Los Angeles Department of Water and Power (LADWP) Scattergood Generating Station project. [1] An article in Hydrogen Insight [10] states that the actual status of this project is that the LADWP is to conduct a new or updated assessment and report the results to council in six months. Projects such as this, or technology tests, do not present an available option for meeting the EPA guidelines in the timelines specified.

An effort to determine the status of hydrogen firing was undertaken through searching publicly available information. Only two tests that were performed in North America were verified. The test with the most publicly available information was the New York Power Authority (NYPA) test on a GE LM6000 turbine in 2022. In their report, NYPA claimed to have burned from 5% to 44% blend by volume at its Brentwood facility. A search showed no publicly available data can be found to verify the duration of the test runs and the related performance. The Electric Power

Research Institute (EPRI) has a summary review of the test on its portal. [11] Information found suggests that the hydrogen was supplied via tube trailers, and due to the limited storage capacity of the trailers on the site, run times were relatively short. The mixing skid and associated piping had to be custom designed for this demonstration. (A mixing skid blends the hydrogen with the natural gas for the prescribed volumetric ratio.)

The second test was carried out at Georgia Power's Plant McDonough on a Mitsubishi M501 G gas turbine at 20% blend by volume. [12] Again, a specially designed fuel mixing skid was employed, and the test was limited by the amount of hydrogen that was available. A search showed no additional publicly available data on this test. In the literature, there is mention of test firing of lower blends in the 5% by volume range, but data are not available. The conclusion is that these very limited and short-duration hydrogen co-firing demonstrations do not provide justification to qualify as being adequately demonstrated today, and much work would be required to meet a 2032 goal on a commercial basis.

Transportation and Storage

As noted above, the gas unit that has the most publicly available information on hydrogen co-firing was the NYPA test fire of the LM6000 at Brentwood. With this information and known performance data of an LM6000, specifically heat rate, a calculation was done to determine what would be required to transport and store enough hydrogen for operation of a single simple cycle combustion turbine. In doing this calculation, a heat rate of 8,600 Btu/kWh LHV was used. This would be a rated performance for a new LM6000. A typical running unit could see a degradation of performance overtime of up to 10%. If that was the case, more hydrogen would be burned for the same output. It was assumed to be fired at the design rated full load of 46.6 MW at standard conditions. The EPA implies in its work that trucking is a cost-effective option up to 200 miles. One hydrogen tube trailer can contain 380 kg of hydrogen compressed to 2,600 pounds per square inch gauge (psig). [13] Using calculations from the LM6000 mentioned above, nine tube trailers would be required for each hour of full load operation, or more than 200 trucks a day for a single 46.6 MW machine. The logistics of moving this many trucks would be unmanageable. The other option is to store on site the equivalent amount of hydrogen. Although not sized here, this would be a significant sized high-pressured tank.

While the EPA's support document states that there are about 1,600 miles of dedicated hydrogen pipeline services that exist, it is very user-specific, transporting hydrogen between oil, gas, and chemical process facilities. [14] This is compared to the about 3 million miles of natural gas pipeline installed. In the discussion section on transportation and storage, the EPA states that analysts "assert that 20 percent hydrogen concentrations by volume may be the maximum blend before significant pipeline upgrades are required." In doing literature research on the subject, very little definitive data were found. Some researchers say this number could be 5%-15%. [15] The IEA Global Hydrogen Review 2022 makes it clear that that upper bound of 20% hydrogen blend in pipelines without significant infrastructure changes is limited to certain distribution networks and would still require some upgrading. For natural gas transmission networks, the IEA notes that research indicates levels of only 5-10% of hydrogen blending is feasible without significant upgrades.

Another option could be a dedicated hydrogen pipeline. It could be designed to move approximately 88% of the equivalent energy of a natural gas pipeline in the same diameter pipe. [15] To do this, additional compression would be required. The construction of a new pipeline would also face all the challenges, costs, and timelines related to permitting, design, and construction. It is noted that due to the molecular weight of hydrogen, compressors need to operate at three times the speed of natural gas compressors. This requires specialized equipment and more energy to compress the gas.

If existing gas lines are to be used for hydrogen blends, then consideration needs to be given to all users. This often includes gas distribution companies that provide gas to residential and commercial services. Various studies are being carried out in Europe on how much hydrogen could be safely blended for this use, and 1% to 5% is the most recognized range of blends identified. Since the EPA's target date for 30% blending is 2032, we can rule out this option.

Conclusions

After reviewing the EPA technical document on hydrogen development, I can make several conclusions. One of the most important is the document's assertion that there is available pipeline capacity in the United States to meet the EPA requirements. This is not accurate. Although there is much talk about blending hydrogen into the natural gas transmission and distribution system, an amount of between 1% and 5% is likely all that is practical without major changes to end use equipment. This does not meet an EPA 30% blend target in 2032. The EPA proposes trucking on tube trailers for transport. As the LM6000 example shows, the logistics of moving this many trucks are not feasible. That would only leave on-site storage as an option, which the EPA does not adequately assess or account for in its support document.

The EPA's technical document reviewed the technical readiness level of the various turbine options. Although there is a lot of marketing or forecast development of machines that will run at 30% blends, they are neither demonstrated nor commercially available with guaranteed performance today to be a viable option to meet the EPA requirements.

As mentioned in the production section discussion, the EPA's targeted price for low-GHG hydrogen of $0.5/kg used in the modelling is not a reasonable assumption for the early years of compliance requirements.

To summarize:

1) Approximately 176 MW of renewable electricity is required to produce enough green hydrogen to generate 46.6 MW of electricity, firing in a gas turbine at 100% hydrogen.
2) The only available transport currently being used to get hydrogen to test sites is tube trailer trucks. To run one LM6000 at full load (46.6 MW) for 24 hours would require more than 200 tube trailer truckloads to be delivered and unloaded daily.
3) Although hydrogen can be transported in specially built pipelines, there will not be a sufficient network available in the foreseeable future.

4) A hydrogen production price of $0.5/kilogram (kg) or $1/kg, as referenced by the EPA, is based solely on the Department of Energy's goals. [3] This is significantly lower than the current estimated cost of $5/kg of hydrogen produced by electrolysis and significantly lower than even the International Energy Agency's most optimistic projections of future hydrogen costs.

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Mr. Doug Campbell is a professional engineer with demonstrated managerial ability including planning, financial control, contract management, staff supervision and reporting. Over a 48-year career, Mr. Campbell has developed a wide range of technical skills associated with the design construction and start-up of new generation and the operation and maintenance of existing generation facilities. He has held positions as Manager of Hydro, Manager of a Multi-unit Steam Plant and Combustion Turbine operation, as well as Director of Generation Services in a vertically-integrated utility. As a Senior Technical Advisor, Mr. Campbell contributed to various engineering problems, such as recent studies on inspection and evaluation of fitness for service for high pressure equipment and various pressure retaining component parts. His involvement as an independent contractor has been in providing expert advice on new and developing technologies to support the transformation of the electrical grid. Current work includes providing insights in these developments, especially as related to a low carbon world. Mr. Campbell completed a Master of Science in Energy from Heriot-Watt University in 2018 and a Master of Applied Economics from Saint Mary’s University in 2022, which has allowed him to obtain additional skills to evaluate technology and to comment on the strategic outcomes of their application.

Reference calculation and terminology to be aware of in Hydrogen Natural Gas Comparisons

Doug Campbell

July 11, 2023

Conversion Factors

Definition of and calculation of decatherms for natural gas consumption and billing

Explanation as found in Wikipedia, often useful never cited.

The **therm** (symbol, **thm**) is a non-SI unit of heat energy equal to 100,000 British thermal units (BTU),[1] and approximately 105 megajoules, 29 kilowatt-hours, 25200 kilocalories and 25.2 thermies. One therm is the energy content of approximately 100 cubic feet (2.83 cubic metres) of natural gas at standard temperature and pressure. However, the BTU is not standardised worldwide, with slightly different values in the EU, UK, and USA, meaning that the energy content of the therm also varies by territory.

Natural gas meters measure volume and not energy content, and given that the energy density varies with the mix of hydrocarbons in the natural gas, a 'therm factor' is used by natural gas companies to convert the volume of gas used to its heat equivalent, usually being expressed in units of 'therms per CCF' (CCF is an abbreviation for 100 cubic feet). Higher than average concentration of ethane, propane or butane will increase the therm factor and the inclusion of non-flammable impurities, such as carbon dioxide or nitrogen will reduce it. The Wobbe Index of a fuel gas is also sometimes used to quantify the amount of heat per unit volume burnt.

Definitions

- Therm (EC) ≡ 100000 BTU_{ISO}[2]

  = 105506000 joules
  ≈ 29.3072 kWh
  The therm (EC) is often used by engineers in the US.

- Therm (US) ≡ 100000 $BTU_{59\,°F}$[3]

  = 105480400 joules
  ≈ 29.3001111111111 kWh.

- Therm (UK) ≡ 105505585.257348 joules[4]

  ≡ 29.3071070159300 kWh

Decatherm

A **decatherm** or **dekatherm**[5] (dth or Dth) is 10 therms, which is 1,000,000 British thermal units or 1.055 GJ.[6][7] It is a combination of the prefix for 10 (deca, often with the US spelling "deka") and the energy unit therm. There is some ambiguity, as "decatherm" uses the prefix "d" to mean 10, where in metric the prefix "d" means "deci" or one-tenth, and the prefix "da" means "deca", or 10, though decatherm may use a capital "D". The energy content of 1,000 cubic feet (28 m^3) natural gas measured at standard conditions is approximately equal to one dekatherm.

This unit of energy is used primarily to measure natural gas. Natural gas is a mixture of gases containing approximately 80% methane (CH_4) and its heating value varies from about or 10.1 to 11.4 kilowatt-hours per cubic metre (975 to 1,100 Btu/cu ft), depending on the mix of different gases in the gas stream. The volume of natural gas with heating value of one dekatherm is about 910 to 1,026 cubic feet (25.8 to 29.1 m^3). Noncombustible carbon dioxide (CO_2) lowers the heating value of natural gas. Heavier hydrocarbons such as ethane (C_2H_6), propane (C_3H_8), and butane (C_4H_{10}) increase its heating value. Since customers who buy natural gas are actually buying heat, gas distribution companies who bill by volume routinely adjust their rates to compensate for this.[8]

The company Texas Eastern Transmission Corporation, a natural gas pipeline company, started to use the unit dekatherm in about 1972. To simplify billing, Texas Eastern staff members coined the term dekatherm and proposed using calorimeters to measure and bill gas delivered to customers in dekatherms.[9] This would eliminate the constant calculation of rate adjustments to dollar per 1000 cubic feet rates in order to assure that all customers received the same amount of heat per dollar. A settlement agreement reflecting the new billing procedure and settlement rates was filed in 1973. The Federal Power Commission issued an order approving the settlement agreement and the new tariff using dekatherms later that year,[10] Other gas distribution companies also began to use this process.[11]

In spite of the need for adjustments, many companies continue to use cubic feet rather than dekatherms to measure and bill natural gas.[12][13]

Referenced from " Kyle's Converter"

https://www.kylesconverter.com/energy,-work,-and-heat/cubic-feet-of-natural-gas-to-dekatherms-(us)

Unit Descriptions	
1 Cubic Foot of Natural Gas:	1 Dekatherm (US):
1000 BTU_{IT}	Roughly energy equivalent of a thousand cubic feet of natural gas (MCF). Equivalent to 1 000 000 BTU; dekatherm (US) based on the $BTU_{59^{\circ}f}$ popular in USA. 1 Dekatherm (Dth US) = 1 054 804 000 joules (J).

Link to Your Exact Conversion
https://www.kylesconverter.com/energy,-work,-and-heat/cubic-feet-of-natural-gas-to-dekatherms-(us)#400000

Conversions Table	
1 Cubic Feet Of Natural Gas to Dekatherms (us) = 0.001	70 Cubic Feet Of Natural Gas to Dekatherms (us) = 0.07
2 Cubic Feet Of Natural Gas to Dekatherms (us) = 0.002	80 Cubic Feet Of Natural Gas to Dekatherms (us) = 0.08
3 Cubic Feet Of Natural Gas to Dekatherms (us) = 0.003	90 Cubic Feet Of Natural Gas to Dekatherms (us) = 0.09
4 Cubic Feet Of Natural Gas to Dekatherms (us) = 0.004	100 Cubic Feet Of Natural Gas to Dekatherms (us) = 0.1
5 Cubic Feet Of Natural Gas to Dekatherms (us) = 0.005	200 Cubic Feet Of Natural Gas to Dekatherms (us) = 0.2
6 Cubic Feet Of Natural Gas to Dekatherms (us) = 0.006	300 Cubic Feet Of Natural Gas to Dekatherms (us) = 0.3001
7 Cubic Feet Of Natural Gas to Dekatherms (us) = 0.007	400 Cubic Feet Of Natural Gas to Dekatherms (us) = 0.4001
8 Cubic Feet Of Natural Gas to Dekatherms (us) = 0.008	500 Cubic Feet Of Natural Gas to Dekatherms (us) = 0.5001
9 Cubic Feet Of Natural Gas to Dekatherms (us) = 0.009	600 Cubic Feet Of Natural Gas to Dekatherms (us) = 0.6001
10 Cubic Feet Of Natural Gas to Dekatherms (us) = 0.01	800 Cubic Feet Of Natural Gas to Dekatherms (us) = 0.8002
20 Cubic Feet Of Natural Gas to Dekatherms (us) = 0.02	900 Cubic Feet Of Natural Gas to Dekatherms (us) = 0.9002
30 Cubic Feet Of Natural Gas to Dekatherms (us) = 0.03	1,000 Cubic Feet Of Natural Gas to Dekatherms (us) = 1.0002
40 Cubic Feet Of Natural Gas to Dekatherms (us) = 0.04	10,000 Cubic Feet Of Natural Gas to Dekatherms (us) = 10.0024
50 Cubic Feet Of Natural Gas to Dekatherms (us) = 0.05	100,000 Cubic Feet Of Natural Gas to Dekatherms (us) = 100.0239
60 Cubic Feet Of Natural Gas to Dekatherms (us) = 0.06	1,000,000 Cubic Feet Of Natural Gas to Dekatherms (us) = 1000.2388

Calculation:

# of million cubic feet * Btu energy = dekatherms

Important things to be aware of:

Carbon dioxide emission coefficients in fuel is stated in:

lbs CO2 per million btu of fuel (Ex. Natural gas 116.65 of fuel burned)

EPA emission limits are stated in CO_2 /MWh -gross:

Example is 1,150 lb CO_2/MWh -Gross

Gas turbine efficiency calculations utilize Low Heating Values.

This is important to be aware of as conventional boilers following ASME heat rate calculations determine heat rate by HHV high heating value. Generally, units are dispatched on the HHV calculation.

Rule of thumb is to HHV = 1.11 * LHV.

Hydrogen Natural gas Comparisons:

Always be aware if you are talking by volume or by mass. Generally speaking, when suppliers are talking blending, they will be speaking in terms of % by volume.

6 Important properties of Natural Gas and Hydrogen

The following is extracted from Power Engineers:

https://www.powereng.com/library/6-things-to-remember-about-hydrogen-vs-natural-gas

Chemical Formula:	Hydrogen: H_2 Natural gas (methane): CH_4
Molecular Weight:	Hydrogen: 2 Natural gas (methane): 16
Flammability Limit	Hydrogen :4%/75% Natural Gas: 7%/20%
Flame Speed	Hydrogen :200-300cm/sec Natural Gas: 30-40cm/sec
Adiabatic Flame Temperature	Hydrogen :4000F Natural Gas: 3565 F
Heating value LHV (BTU/Lb)	Hydrogen: 51623Btu/lb. Natural Gas :(methane) 21518 Btu/lb
Volumetric LHV (Btu/ft^3)	Hydrogen: 266 Btu/ft^3 Natural Gas (methane): 881Btu/ft^3

Note: Absolute numbers vary depending on refence used. This reflects different gas quality from various processors.

Calculation for LM 6000 Gas Turbine with associated Reference Material

Doug Campbell

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Calculation of LM 6000 fuel requirements:

Heat rate LHV = 8600 Btu/kwh

Heating Value Natural Gas LHV = 21,500 Btu/Lb (CH_4)

Fuel Burned:

8,600/21500 = .4Lb/kwh Btu/kwh /btu/Lb = Lb /kwh

.4Lb/kwh * 1000 kwh /MWh = 400 Lb/MWh

1 MWh = 3.412 mmBtu

400Lb/MWh * 1Mwh/3.412 = 117 Lb/mmBtu

21,500 Btu/ln * 400 Lb/MWh = 8.6 * 10^6 Btu/MWh

Co_2 emissions = 116.65 LbCO_2/MBtu

CO_2 = 116.65 * 8.6 = 1003.19 Lb/MWh

LM 6000 full load meets CO_2 limit.

Full Load Calculation:

Fuel burned = 400 Lb/MWh

Full load = 46.6MW

Fuel burned: 400 * 46.6 = 18,600 Lb /hr

Btu input:

18,600 Lb/Hr * 21,500 Btu/lb.= 400.76 MMBtu/Hr.

Calculate number of tube trailers required 380 Kg trailers.

Hydrogen = 51,591Btu/Lb

One hour use = 400.76 MM Btu/51591 Btu/Lb = 7,780 Lb/hr = 3530.9 Kg/hr

Therefore 9 .29 tube trailers per hour required at full load.

Volume calculation:

NG = 964 Btu/ft^3

H_2 = 290 Btu/ft^3

Hydrogen = 400.76 mmBtu/hr * 1ft^3/290 Btu = 1.38 * 10^6 ft^3/hr

Natural Gas = 400.76mmbtu * 1ft^3 / 964 Btu = .41 * 10^6 ft^3/hr

When sizing pipe it is important to maintain the maximum allowable velocity in the pipe. We can see that velocities will increase greatly with hydrogen vs. natural gas. Therefore, in order to meet full load either pipelines need to be made larger or the pressure to maintain energy density needs to increased. A detailed engineering study by a piping engineer would be required to optimize the solution.

2.1 Low Density and Energy Content

Hydrogen has the lowest mass density of any substance in the universe, with an atomic weight of only 2.0. It is about eight times lighter than methane (CH_4) [1]. Because of this, there is a common misconception that hydrogen is a superior fuel to natural gas because of its larger heating value (141.86 MJ/kg for H_2 versus 55.53 MJ/kg for pure methane). However, this is due to the fact that hydrogen is *very light* compared to natural gas, not because it actually contains that much energy on a volume basis compared to natural gas. On a molecular basis, there is more energy contained within four C-H bonds compared to one single H-H bond. Also, gas turbine combustors are of fixed volume and designed to work at specific operating pressures with little room for deviation. Therefore, the amount of hydrogen that can be used in a particular gas turbine is limited by volume. Indeed, looking at the energy content on a per-unit-volume or mole basis reveals that natural gas has more than three times the energy density of hydrogen by volume (10,050 kJ/m^3 H_2 versus 32,560 kJ/m^3 CH_4) [1]. Thus, to accommodate hydrogen fuel, hydrogen gas turbines will either need to be larger, incorporate higher max pressures to reduce gas volumes, or both to compete with natural gas turbines. This means that, to achieve similar performance/emissions ratings to their natural gas counterparts, hydrogen turbines may be more costly to produce.

How do you calculate specific fuel consumption of gas turbine?

A simple-cycle gas turbine used for power generation has a thermal efficiency of about 34 percent. Since 1 kwh is theoretically equivalent to 3,415 Btu,the simple-cycle gas turbine has a fuel connsumption of:3,415 / 0.34 = about 10,000 Btu/kwh.

Given the heating value (i.e, heat of combustion) of a fuel, we can easily calculate thesimple-cycle gas turbine fuel usage.

For example, natural gas has a net heating value of about 21,500 Btu/pound.Thus, the natural gas consumption in a simple-cycle gas turbine would be:10,000 / 21,500 = 0.47 pounds/kwh = 0.21 kg/kwh.

As another example, a typical diesel oil has a net heating value of 130,000 Btu/gallon.Thus, the diesel oil consumption in a simple-cycle gas turbine would be:10,000 / 130,000 = 0.077 gallon/kwh.

(The gallon used just above is the U.S. gallon rather than the Imperial gallon)A combined-cycle gas turbine will have a higher thermal efficiency and, hence, lower fuel consumptions.

	LM6000 PC	LM6000 PG	LM6000 PF	LM6000 PF+
Net output (MW)	46.6/51.1*	56/57.2*	44.7/50*	53.9/57.1*
Net heat rate (Btu/kWh, LHV)	8533	8728	8248	8357
Net heat rate (kJ/kWh, LHV)	9002	9208	8702	8817
Net efficiency (%, LHV)	40%	39.1%	41.4%	40.8%
Ramp rate (MW/minute)	30	30	30	30
Startup time (cold iron) (min.)	5	5	5	5
GT Min. Turn Down Load (%)	25%	25%	50%	50%

LM6000 gas turbines can start up in 5 minutes

*MW output without SPRINT/with SPRINT

NOTE: All ratings are based on ISO conditions and natural gas fuel. Actual performance will vary with project-specific conditions and fuel.

Fuels - Higher and Lower Calorific Values

Higher and lower calorific values (heating values) for fuels like coke, oil, wood, hydrogen and others.

Energy content or calorific value is the same as **the heat of combustion**, and can be calculated from thermodynamical values, or measured in a suitable apparatus:

A known amount of the fuel is burned at constant pressure and under standard conditions (0°C and 1 bar) and the heat released is captured in a known mass of water in a calorimeter. If the initial and final temperatures of the water is measured, the energy released can be calculated using the equation

$$H = \Delta T\, mC_p$$

where H = heat energy absorbed (in J), ΔT = change in temperature (in °C), m = mass of water (in g), and C_p = specific heat capacity (4.18 J/g°C for water). The resulting energy value divided by grams of fuel burned gives the energy content (in J/g).

The combustion process generates water vapor and certain techniques may be used to recover the quantity of heat contained in this water vapor by condensing it.

- **Higher Calorific Value** (= Gross Calorific Value - GCV = Higher Heating Value - HHV) - the water of combustion is entirely condensed and the heat contained in the water vapor is recovered
- **Lower Calorific Value** (= Net Calorific Value - NCV = Lower Heating Value - LHV) - the products of combustion contains the water vapor and the heat in the water vapor is not recovered

The table below gives the gross and net heating value of fossil fuels as well as some alternative biobased fuels.

See also Heat of combustion, Fossil and Alternative Fuels - Energy Content and Combustion of Fuels - Carbon Dioxide Emission

Fuel	Density @0°C/32°F, 1 bar		Higher Heating Value (HHV) (Gross Calorific Value - GCV)					Lower Heating Value (LHV) (Net Calorific Value - NCV)				
Gaseous fuels	[kg/m³]	[g/ft³]	[kWh/kg]	[MJ/kg]	[Btu/lb]	[MJ/m³]	[Btu/ft³]	[kWh/kg]	[MJ/kg]	[Btu/lb]	[MJ/m³]	[Btu/ft³]
Acetylene	1.097	31.1	13.9	49.9	21453	54.7	1468					
Ammonia				22.5	9690							
Hydrogen	0.090	2.55	39.4	141.7	60920	12.7	341	33.3	120.0	51591	10.8	290
Methane	0.716	20.3	15.4	55.5	23874	39.8	1069	13.9	50.0	21496	35.8	964
Natural gas (US market)*	0.777	22.0	14.5	52.2	22446	40.6	1090	13.1	47.1	20262	36.6	983
Town gas						18.0	483					
	@15°C/60°F											
Liquid fuels	[kg/l]	[kg/gal]	[kWh/kg]	[MJ/kg]	[Btu/lb]	[MJ/l]	[Btu/gal]	[kWh/kg]	[MJ/kg]	[Btu/lb]	[MJ/l]	[Btu/gal]
Acetone	0.787	2.979	8.83	31.8	13671	25.0	89792	8.22	29.6	12726	23.3	83580
Butane	0.601	3.065	13.64	49.1	21109	29.5	105875	12.58	45.3	19475	27.2	97681
Butanol	0.810		10.36	37.3	16036	30.2	108359	9.56	34.4	14789	27.9	99934
Diesel fuel*	0.846	3.202	12.67	45.6	19604	38.6	138412	11.83	42.6	18315	36.0	129306
Dimethyl ether (DME)	0.665	2.518	8.81	31.7	13629	21.1	75655	8.03	28.9	12425	19.2	68973
Ethane	0.572	2.165	14.42	51.9	22313	29.7	106513	13.28	47.8	20550	27.3	98098
Ethanol (100%)	0.789	2.987	8.25	29.7	12769	23.4	84076	7.42	26.7	11479	21.1	75583
Diethyl ether (ether)	0.716	2.710	11.94	43.0	18487	30.8	110464					
Gasoline (petrol)*	0.737	2.790	12.89	46.4	19948	34.2	122694	12.06	43.4	18659	32.0	114761

Gas oil (heating oil)*	0.84	3.180	11.95	43.0	18495	36.1	129654	11.89	42.8	18401	36.0	128991
Glycerin	1.263	4.781	5.28	19.0	8169	24.0	86098					
Heavy fuel oil*	0.98	3.710	11.61	41.8	17971	41.0	146974	10.83	39.0	16767	38.2	137129
Kerosene*	0.821	3.108	12.83	46.2	19862	37.9	126663	11.94	43.0	18487	35.3	126663
Light fuel oil*	0.96	3.634	12.22	44.0	18917	42.2	151552	11.28	40.6	17455	39.0	139841
LNG*	0.428	1.621	15.33	55.2	23732	23.6	84810	13.50	48.6	20894	20.8	74670
LPG*	0.537	2.033	13.69	49.3	21195	26.5	94986	12.64	45.5	19561	24.4	87664
Marine gas oil*	0.855	3.237	12.75	45.9	19733	39.2	140804	11.89	42.8	18401	36.6	131295
Methanol	0.791	2.994	6.39	23.0	9888	18.2	65274	5.54	19.9	8568	15.8	56562
Methyl ester (biodiesel)	0.888	3.361	11.17	40.2	17283	35.7	128062	10.42	37.5	16122	33.3	119460
MTBE	0.743	2.811	10.56	38.0	16337	28.2	101244	9.75	35.1	15090	26.1	93517
Oils vegetable (biodiesel)*	0.92	3.483	11.25	40.5	17412	37.3	133684	10.50	37.8	16251	34.8	124772
Paraffin (wax)*	0.90	3.407	12.78	46.0	19776	41.4	148538	11.53	41.5	17842	37.4	134007
Pentane	0.63	2.385	13.50	48.6	20894	30.6	109854	12.60	45.4	19497	28.6	102507
Petroleum naphtha*	0.725	2.745	13.36	48.1	20679	34.9	125145	12.47	44.9	19303	32.6	116819
Propane	0.498	1.885	13.99	50.4	21647	25.1	89963	12.88	46.4	19927	23.1	82816
Residual oil*	0.991	3.752				41.8	150072	10.97	39.5	16982	39.2	140470
Tar*			10.00	36.0	15477							
Turpentine	0.865	3.274	12.22	44.0	18917	38.1	136555					
Solid fuels*			**[kWh/kg]**	**[MJ/kg]**	**[Btu/lb]**			**[kWh/kg]**	**[MJ/kg]**	**[Btu/lb]**		
Anthracite coal			9.06	32.6	14015							
Bituminous coal			8.39	30.2	12984			8.06	29.0	12468		
Carbon			9.11	32.8	14101							
Charcoal			8.22	29.6	12726			7.89	28.4	12210		
Coke			7.22	26.0	11178							
Lignite (brown coal)			3.89	14.0	6019							
Peat			4.72	17.0	7309							
Petroleum coke			8.69	31.3	13457			8.19	29.5	12683		
Semi anthracite			8.19	29.5	12683							
Sub-Bituminous coal			6.78	24.4	10490							
Sulfur (s)			2.56	9.2	3955			2.55	9.2	3939		
Wood (dry)	0.701		4.50	16.2	6965			4.28	15.4	6621		

* Fuels which consist of a mixture of several different compounds may vary in quality between seasons and markets. The given values are for fuels with the given density. The variation in quality may give heating values within a range 5 -10% higher and lower than the given value. Also the solid fuels will have a similar quality variation for the different classes of fuel.

- 1 Btu(IT)/lb = 2.3278 MJ/t = 2327.8 J/kg = 0.55598 kcal/kg = 0.000646 kWh/kg
- 1 kcal/kg = 1 cal/g = 4.1868 MJ/t = 4186.8 J/kg = 1.8 Btu(IT)/lb = 0.001162 kWh/kg
- 1 MJ/kg = 1000 J/g = 1 GJ/t = 238.85 kcal/kg = 429.9 Btu(IT)/lb = 0.2778 kWh/kg
- 1 kWh/kg = 1547.7 Btu(IT)/lb = 3.597 GJ/t = 3597.1 kJ/kg = 860.421 kcal/kg

- 1 Btu(IT)/ft^3 = 0.1337 Btu(IT)/gal(US liq) = 0.03531 Btu(IT)/l = 8.89915 kcal/m^3 = 3.7259x10^4 J/m^3
- 1 Btu(IT)/gal(US liq) = 0.2642 Btu(IT)/l = 7.4805 Btu(IT)/ft^3 = 66.6148 kcal/m^3 = 2.7872x10^5 J/m^3
- 1 MJ/m^3 = 26.839 Btu(IT)/ft^3 = 3.5879 Btu(IT)/gal(US liq) = 0.94782 Btu(IT)/l = 239.01 kcal/m^3
- 1 kcal/m^3 = 0.11237 Btu(IT)/ft^3 = 0.01501 Btu(IT)/gal(US liq) = 0.003966 Btu(IT)/l = 4186.8 J/m^3

Carbon Dioxide Emissions Coefficients

Release Date: October 5, 2022 | XLS | METHODOLOGY

Carbon Dioxide Emissions Coefficients by Fuel

Carbon Dioxide (CO_2) Factors:	Pounds CO_2 Per Unit of Volume or Mass	Kilograms CO_2 Per Unit of Volume or Mass	Pounds CO_2 Per Million Btu	Kilograms CO_2 Per Million Btu
For homes and businesses				
Propane	12.68 gallon	5.75 gallon	138.63	62.88
Diesel and Home Heating Fuel (Distillate Fuel Oil)	22.45 gallon	10.19 gallon	163.45	74.14
Kerosene	21.78 gallon	9.88 gallon	161.35	73.19
Coal (All types)	3,876.61 short ton	1,758.40 short ton	211.87	96.10
Natural Gas	120.96 thousand cubic feet	54.87 thousand cubic feet	116.65	52.91
Finished Motor Gasoline[a]	17.86 gallon	8.10 gallon	148.47	67.34
Motor Gasoline	19.37 gallon	8.78 gallon	155.77	70.66
Residual Heating Fuel (Businesses only)	24.78 gallon	11.24 gallon	165.55	75.09
Other transportation fuels				
Jet Fuel	21.50 gallon	9.75 gallon	159.25	72.23
Aviation Gas	18.33 gallon	8.32 gallon	152.54	69.19
Industrial fuels and others not listed above				
Petroleum coke	32.86 gallon	14.90 gallon	225.13	102.12
Nonfuel uses				
Asphalt and Road Oil	26.25 gallon	11.91 gallon	166.12	75.35
Lubricants	23.58 gallon	10.70 gallon	163.29	74.07
Naphthas for Petrochemical Feedstock Use	18.74 gallon	8.50 gallon	149.95	68.02
Other Oils for Petrochemical Feedstock Use	22.61 gallon	10.26 gallon	163.05	73.96
Special Naphthas (solvents)	19.94 gallon	9.04 gallon	159.57	72.38
Waxes	21.10 gallon	9.57 gallon	160.06	72.60
Coals by type				
Anthracite	5,715.11 short ton	2,592.33 short ton	228.60	103.69
Bituminous	4,933.59 short ton	2,237.84 short ton	205.57	93.24
Subbituminous	3,747.36 short ton	1,699.78 short ton	214.13	97.13
Lignite	2,813.18 short ton	1,276.04 short ton	216.40	98.16
Coke	7,196.24 short ton	3,264.17 short ton	250.59	113.67
Other fuels				
Geothermal (steam)	NA	NA	26.03	11.81
Geothermal (binary cycle)	NA	NA	0.00	0.00
Municipal solid waste[b,c]	1,552.88 short ton	704.38 short ton	109.98	49.89
Tire-derived fuel[b]	5,306.87 short ton	2,407.16 short ton	189.53	85.97

Geothermal (steam)	NA	NA	26.03	11.81
Geothermal (binary cycle)	NA	NA	0.00	0.00
Municipal solid waste[b,c]	1,552.88 short ton	704.38 short ton	109.98	49.89
Tire-derived fuel[b]	5,306.87 short ton	2,407.16 short ton	189.53	85.97
Waste oil[b]	22.51 gallon	10.21 gallon	163.14	74.00

Data source: arbon factors provided by the U.S. Environmental Protection Agency, Inventory of *U.S. Greenhouse Gas Emissions and Sinks*: 1990-2020, Tables A-22, A-27, A-34, and A-230

[a]Includes fuel ethanol blended into motor gasoline. The fuel ethanol component of finished motor gasoline is treated as nonemissive. See methodology documentation for further details on calculations.

[b]Carbon factors for municipal solid waste, tire-derived fuel, and waste oil are provided by the U.S. Environmental Protection Agency, *Greenhouse Gas Emissions Factor Hub*

[c]The carbon factor for municipal solid waste has been adjusted to apply both to biogenic and non-biogenic waste

Note: To convert to carbon equivalents multiply by 12/44.

Coefficients may vary slightly with estimation method and across time.

Coefficients are based on data from 2020. EIA uses these coefficients for estimating 2021, and more recent, energy-related CO_2 emissions.

Voluntary Reporting Program emissions factors (discontinued)

Attachment K

Analysis of the EPA's Proposed Power Plant Greenhouse Gas Emissions Rule Impact on the Generation Alternative of Fuel Switching to Natural Gas

Regarding: EPA's Proposal 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"
(Docket EPA-HQ-OAR-2023-0072)

Prepared for the National Rural Electric Cooperative Association By:
Dr. William Morris, Carbon Management Strategies, LLC, and
Mr. John Weeda, Quail Hollow, LLC

August 3, 2023

Introduction

The EPA's proposed greenhouse gas (GHG) emissions regulations for existing coal-fired electric generating units (EGUs) ("proposed rules")[1] includes a determination that natural gas co-firing is a "best system of emission reduction" (BSER) for certain coal-fired EGUs. In support of this determination, the EPA includes in its regulatory docket a document entitled "Greenhouse Gas Mitigation Measures for Steam Generating Units Technical Support Document" (Steam EGU TSD).[2] Section 3.3 of that Steam EGU TSD, titled "Evaluation of Natural Gas Co-firing as BSER for Existing Coal-Fired EGUs," contains information about co-firing or converting coal-fired steam generating units to natural gas. Many of the assumptions in that section cannot be generalized to fit the fleet of generating units in the United States. Those deficiencies are addressed in the paragraphs below.

The EPA cites public reports, such as the Energy Information Administration (EIA) 2020 report entitled "More than 100 coal-fired plants have been replaced or converted to natural gas since 2011,"[3] to suggest that conversion to natural gas is a common occurrence and widely available to most coal plants. That is a misleading generalization that is unsupported by facts and experience. As the title of the EIA report indicates, 100 is the total number of units that have converted to natural gas, as well as those that were replaced altogether with gas generation. Indeed, the EIA report states, "At the end of 2010, 316.8 gigawatts (GW) of coal-fired capacity existed in the United States, but by the end of 2019, 49.2 GW of that amount was retired, 14.3 GW had the boiler converted to burn natural gas, and 15.3 GW was replaced with natural gas combined cycle." From those numbers, we see that 15.3 of those GW were replacement rather than fuel switching with the coal-fired boilers. Furthermore, these GWs together are 40% less than the amount of GWs that were retired, presumably because switching them or replacing them with gas was infeasible, uneconomical, or both. The report further states: "Coal-fired plants in the eastern half of the country have been good candidates for conversion because they tend to be smaller-capacity units and are mostly over 50 years old."[4]

The following graphic from the EIA shows that the majority of retired or repurposed coal-fired units were either retired outright or replaced entirely by a natural gas combined cycle unit, and demonstrates how small the percentage is of actual conversions of the coal-fired boilers to natural gas.[5]

[1] "New Source Performance Standards for GHG Emissions from New and Reconstructed EGUs; Emission Guidelines for GHG Emissions from Existing EGUs; and Repeal of the Affordable Clean Energy Rule" (Docket EPA-HQ-OAR-2023-0072)

[2] "Greenhouse Gas Mitigation Measures for Steam Generating Units Technical Support Document" (Docket EPA-HQ-OAR-2023-0072)

[3] https://www.eia.gov/todayinenergy/detail.php?id=44636

[4] https://www.power-eng.com/emissions/coal-to-gas-plant-conversions-in-the-u-s/#gref

[5] https://www.eia.gov/todayinenergy/detail.php?id=44636

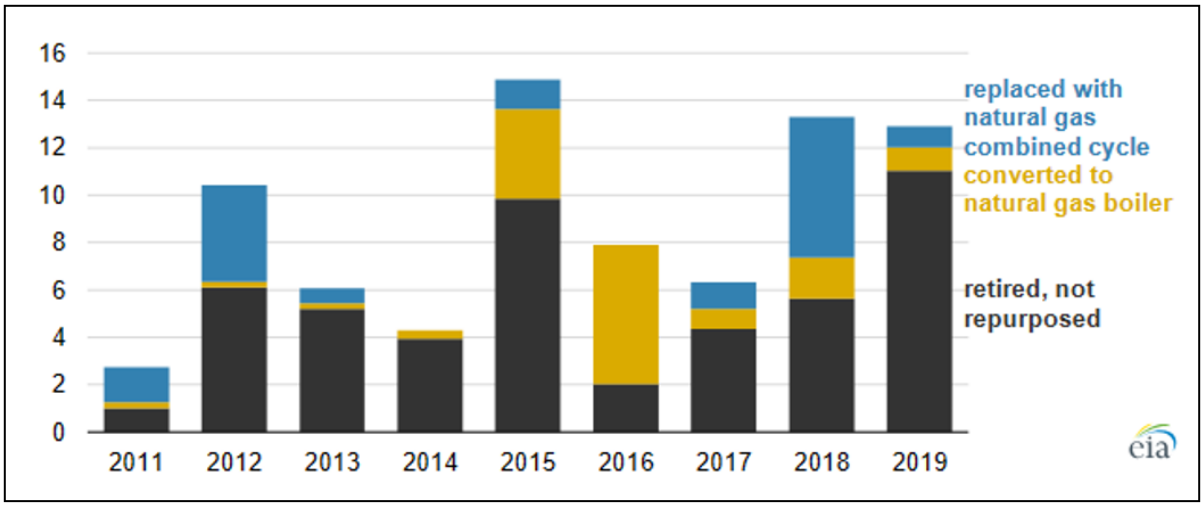


Figure 1: U.S. coal-fired capacity retired or repurposed to natural gas by conversion type (2011-2019) gigawatts (Source: EIA)

With that note of caution, let us examine the reasons why converting coal plants to natural gas is often not a practical option.

The Sargent & Lundy report entitled "Natural Gas Co-Firing Memo" (Project No. 13527-002 March 2023),[6] which is referenced by the EPA, provides a general description of co-firing natural gas in a coal boiler, including for ignition/warm-up. Most coal boilers require an ignition fuel to be utilized to ignite the coal on startup. If natural gas is available, it is one of the easiest ignition fuels to use, but using natural gas for ignition is not the same as co-firing with natural gas. In fact, it is common practice to shut down the natural gas igniters once the flame is established, so co-firing during normal operation is not as common a practice as the report would suggest.

However, the EPA inappropriately extrapolates that common practice of using natural gas in a limited way for startup to justify its claims that switching to natural gas or co-firing at levels required in its proposed rules are technically feasible. In its Steam EGU TSD, EPA states that 249 of 565 coal-fired units reported using natural gas "as a fuel **or startup source.**" From this, the EPA concludes – without basis – that higher levels of co-firing are "immediately available" at some coal units, based only on speculative discussion that some of those EGUs may have the ability to co-fire at higher levels and may be able to do so for significant periods of time.[7]

Several factors contribute to the practice of only using small amounts of natural gas for ignition fuel, including limitations related to the supply of natural gas, quantity available, and operational aspects of the boiler. These issues are discussed in further detail in this document. As the relatively low number of natural gas boiler conversions in the EIA data above indicates,

[6] Natural Gas Co-Firing Memo, Sargent & Lundy (2023). Available at Docket ID EPA-HQ-OAR-2023-0072.

[7] "Greenhouse Gas Mitigation Measures for Steam Generating Units Technical Support Document" (Docket EPA-HQ-OAR-2023-0072)

however, the choice to switch to natural gas as the primary fuel, or to cofire significant quantities of natural gas for the boiler, is often neither feasible nor economical.

Finally, it is clear that significant levels of natural gas co-firing at existing coal units will have an impact on generating capacity of those units. The Sargent & Lundy report states that: "If steam temperatures are reduced, this lowers generator output and increases all heat rates." This will have a large impact on utility decisions with the current need to retain dispatchable capabilities in the fleet. This is in direct conflict with the EPA's assumptions in its March 2023 Integrated Planning Model assumptions (Table 5-18 Cost and Performance Assumptions for Coal-to-Gas Retrofits in v6 on page 5-23) where the EPA states that there will be no capacity loss from coal to gas conversion.[8]

Availability of Natural Gas During Periods of Inclement Weather and High Demand

The EPA has proposed that one option for cutting greenhouse gas emissions from coal-fired power stations is to utilize natural gas co-firing to reduce the carbon emissions per unit of heat input at the power station. While this may be possible in some cases, it is not feasible in many more other cases. For example, extreme winter weather has shown the risks of depending too much on natural gas for power generation. During winter storm Elliott, PJM Interconnection, the nation's largest system operator, experienced significant failures of natural gas fired power generators. During this event, the system was at severe risk of not being able to meet load. In the aftermath, PJM's analysis showed that "about 63% of all outages were natural gas" and that the failures were a result of the rapid onset of cold temperatures that "heavily impacted natural gas production, particularly in the Marcellus and Utica basins, which are the predominant source of the natural gas procured for gas generation in the PJM footprint. This led to significant loss of gas supply for all downstream gas consumers, particularly larger, more-efficient gas-fired power generation units that require nominated supply and higher pipeline pressures to operate."[9]

Clearly, this event shows the risk of relying more heavily on natural gas as a fuel source, which may not be available to power generators when necessary. The supply of natural gas is already insufficient in the PJM region without the forced fuel switching and blending requirements that the EPA is proposing. Unless and until the EPA demonstrates that the existing gas infrastructure is able to meet current demand and the increased demand from mandated fuel switching, it is unreasonable to consider fuel switching an achievable option.

Inadequacy of Natural Gas Transmission and Distribution Infrastructure for Fuel Switching

The EPA proposal also assumes that natural gas is readily available for all coal fired power plants to begin fuel switching by 2030 to meet the regulatory mandate. However, this is not factually

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[8] Environmental Protection Agency. *Documentation for EPA's Power Sector Modeling Platform v6 Using the Integrated Planning Model Post-IRA 2022 Reference Case*. March 2023. Available at: https://www.epa.gov/system/files/documents/2023-03/EPA%20Platform%20v6%20Post-IRA%202022%20Reference%20Case.pdf

[9] *Winter Storm Elliott Frequently Asked Questions*, Issued by PJM, Accessed 7/19/23, Available at: https://www.pjm.com/-/media/markets-ops/winter-storm-elliott/faq-winter-storm-elliott.ashx

accurate. As detailed in the discussion that follows, the actual situation for each plant location would need to be studied to determine if a switch is feasible depending on natural gas pipelines proximity, capacity, and offtake limits, as well as feasibility, cost, and timeline for additional pipeline construction where needed.

Even under the most ideal circumstances, however, there are many coal-fired power stations that are not located adjacent to the necessary natural gas infrastructure required for fuel switching or blending, and would thus require additional pipeline infrastructure at a significant cost to the unit owner utility.

Provided below are figures and data from the EIA's Energy Atlas map related to coal-fired unit proximity to the nearest natural gas pipeline.[10] As evidenced by the examples further below, actual distances to pipelines with adequate capacity and offtake potential are often multiple times these distances and require tens or even hundreds of millions of dollars in capital costs alone. But the EIA map provides an illustrative example of the bare minimum distance for possible natural gas co-firing.

According to the EIA data, roughly 17% of coal-fired units nationwide are more than 10 miles from even the single nearest natural gas pipeline and nearly one-third are more than 5 miles.

Figure 2 overlays natural gas infrastructure and the location of coal-fired plants in the PJM area. Nearly half of the coal plants in the region are at least 2.5 miles, with a significant number of units in Eastern Pennsylvania 10 miles or further, from even the nearest natural gas pipeline that may potentially be available for fuel switching.

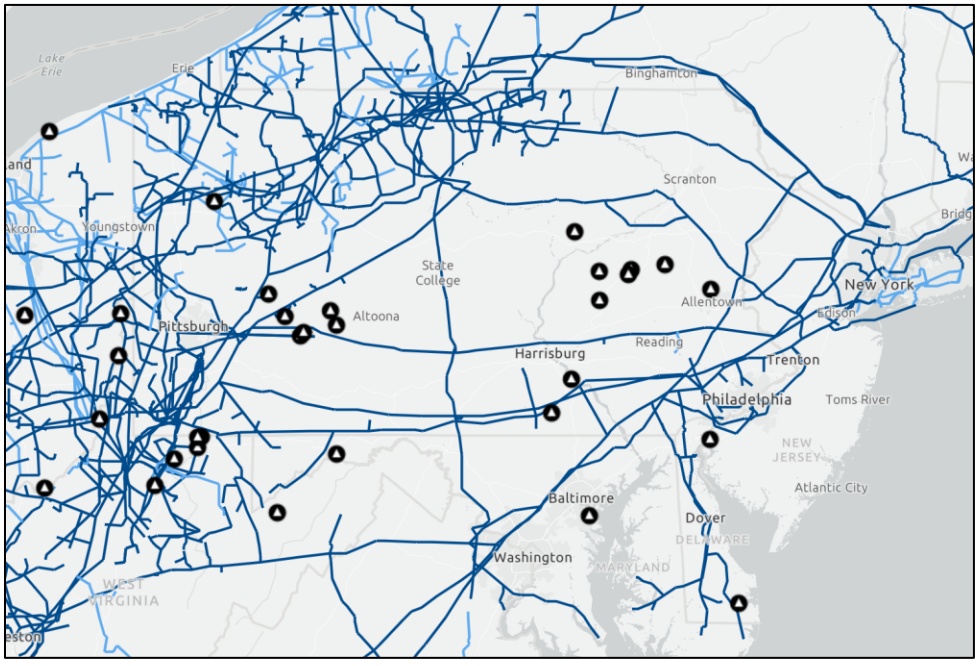


Figure 2. EIA data showing natural gas infrastructure and coal plants in the PJM region.

[10] EIA Energy Atlas Interactive Map, Accessed 7/19/2023, Available at: https://atlas.eia.gov/apps/eia::all-energy-infrastructure-and-resources/explore

This infrastructure mismatch is not limited to the mid-Atlantic or PJM region either. It's apparent, using the same map and data, that this absolute minimum possible distance is even greater in the central portion of the country (Figure 3), as well as the Upper Great Plains and Rocky Mountain Region (Figure 4). In Figure 3, nearly 25% of units are more than 10 miles from the nearest natural gas pipeline, and over half are more than 5 miles. Similar distances can be found in Figure 4, with numerous units more than 10 miles from the nearest natural gas pipeline.

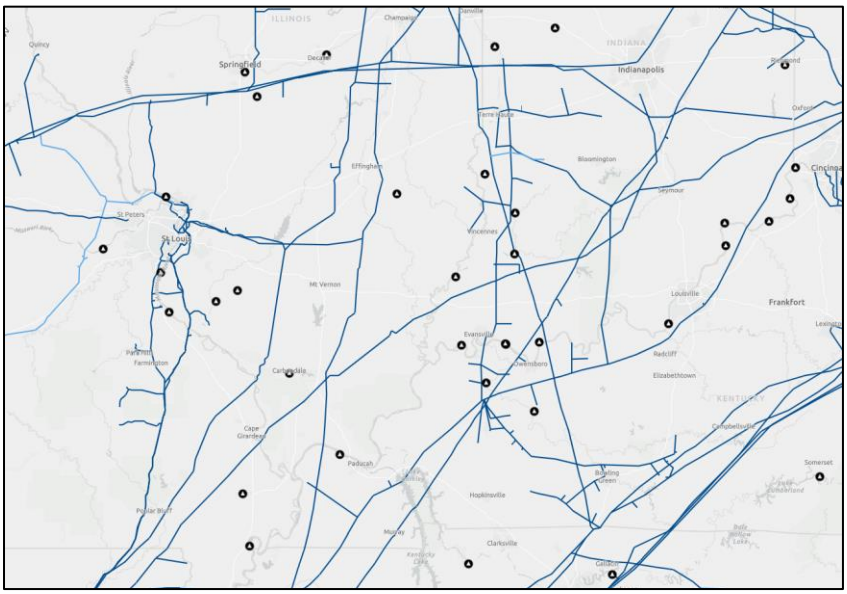


Figure 3. EIA map showing the locations of coal fired power stations and natural gas transmission infrastructure in the Lower Midwest Region.

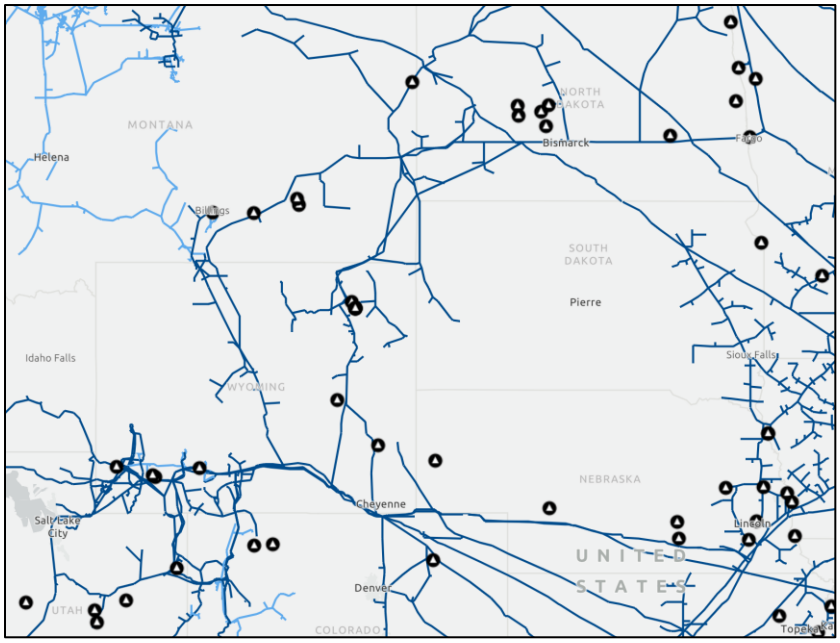


Figure 4. EIA map showing the locations of coal fired power stations and natural gas transmission infrastructure in the Great Plains and Rocky Mountain Region.

Furthermore, the presence of a natural gas pipeline near a plant is not an indication of adequate capacity. For example, Mr. John Weeda, technical expert and consultant to NRECA, is experienced with the Coal Creek Station north of Bismarck, ND. Figure shows a gas line just east of the plant, however, that line does not even have enough capacity to provide ignition fuel for the 1,100 MW coal plant. The nearest pipeline with adequate capacity is over 40 miles from the plant.

The referenced EPA document states that "Even if a generator doesn't necessarily report burning natural gas, in many cases, coal-fired EGUs are located in the vicinity of other generating assets. In the cases where coal-fired EGUs are located near natural gas EGUs, they likely have access to an existing supply of natural gas." This speculation or overgeneralization is no substitute for actually evaluating the availability of natural gas to the units the EPA would make subject to this rule. Pipeline companies need to have lines subscribed to as full an extent as possible for their businesses to be successful. As a result, excess capacity to feed a large unit transitioning from coal to natural gas is often not possible with existing infrastructure.

For example, Mr. Weeda is in discussion with a pipeline company about the potential to supply approximately 100 MW equivalent of gas to a peaking plant being planned as backup to a wind and solar installation in eastern Montana. Although, an existing line runs adjacent to the site, it is unclear whether supplying the plant is even possible. An in-depth analysis of the pipeline's capacity and the potential to shift capacity would be required. In short, proximity to a pipeline alone is not even sufficient to make co-firing, let alone substantial co-firing, a viable option.

Difficulty and Cost Associated with Procuring Natural Gas Service at a Coal Plant

The EPA assumes that natural gas is available at coal plants to provide natural gas co-firing as an option for compliance. However, this is not the case during extreme weather events like winter storms (as discussed extensively in the section "Availability of Natural Gas During Periods of Inclement Weather and High Demand"), for certain plants in certain locations, and can be extremely expensive or impossible for others.

For example, on a simple map, Associated Electric Cooperative's New Madrid Station in Missouri appears close to existing natural gas pipeline infrastructure. However, when the cooperative researched the cost of obtaining natural gas service at their site, the closest pipeline with capacity and pressure to support the plant is located 46 miles away, with an estimated capital cost of $213,798,000 to connect to the plant. At Associated Electric Cooperative's Thomas Hill facility, the closest gas line is 14 miles away, with an estimated capital cost of $59,500,000 to connect. These are likely typical costs for many more power plants. The EPA, however, does not seem to have accounted for these substantial costs in its analyses for the proposed rule. Securing the right-of-way (ROW), surveying, and permitting can be expected to take three years with construction, and another two years if there are not any litigation or challenges to the permits. That is highly unlikely, as recent history of vociferous opposition to natural gas pipelines shows. Even when natural gas service is in close proximity, the cost of connecting to a suitable service line can be prohibitively expensive and is unlikely to be available by 2030.

Furthermore, in the case of Arizona Electric Power Cooperative, Inc. (AEPCO), steam unit 2 of the Apache Generating Station has been converted to natural gas, but additional firm natural gas transportation is not available on the natural gas supply pipeline. If coal-fired steam unit 3, which is the same size as steam unit 2, were converted to natural gas, the current metering station, piping, and transportation contracts would require modifications to reliably deliver the additional gas to the site.

Arkansas Electric Cooperative Corporation has estimated that to continue operating one of their coal-fired units until 2040, less than its remaining life, they would need to invest $70 million to $120 million by 2030, just to bring natural gas to the plant site in order to co-fire with natural gas. Necessary retrofits to the plant to enable co-firing would require additional investment.

Plant Design Challenges

The design challenges that need to be addressed in the conversion of a coal unit to co-fire or fully-utilize natural gas are significant in most cases. The Sargent & Lundy report "Natural Gas Co-Firing Memo" that the EPA references devotes less than a page to this important topic. The mass of the gas from natural gas combustion is different than the mass of gas from burning coal. The flame temperature and the attachment of the flame to the wall of the boiler, the safety characteristics of handling natural gas, the boiler controls for natural gas, and many other factors all need to be considered. In other words, this is a major engineering study of conversion that EPA's single page description does not adequately represent. For example, adding or increasing flue gas recirculation will likely be needed and adding hundreds of horsepower. Heat transfer in the boiler surfaces would be affected, requiring modification or addition of heat transfer surface. The exit gas temperature from the boiler would typically increase, causing shortened life on the equipment at the back of the boiler and downstream. The heat rate measure of unit efficiency is typically negatively affected. A detailed engineering analysis would have to be completed by each unit owner to determine the feasibility of a gas conversion.

For example, AEPCO's Apache Station in Cochise, AZ converted one approximately 200-MW boiler to natural gas and the other one remains on coal. In the conversion process, the need was identified to double the size of the flue gas recirculation system and to direct it to the burner area. Despite these changes, the exit gas temperature of the boiler runs hot and is destructive to equipment in the back pass of the boiler and downstream.

Similarly, Mr. Weeda was responsible for the engineering group at a 1,100-MW lignite-fired power plant. The thermal sciences engineer in the group evaluated natural gas conversion. His findings determined that the large volume of the boiler designed for lignite firing would have major heat transfer imbalance with the enormous difference in flue gas volume with natural gas. This would significantly reduce the efficiency of the boiler, leading to capacity loss, equipment failures, inability to make steam temperature, and other challenges. It is fair to say that most large lignite boilers would experience similar engineering limitations, preventing co-firing from being an achievable option, due to the economics of such a large change. Sargent & Lundy, in their experience report, stated that modifications are more extensive for plants of 500 MW or more.

Cost

Table 1 on page 15 of the EPA Steam EGU TSD includes estimated capital cost and impact on energy cost for a hypothetical "representative" unit. The estimated capital cost is not representative of an actual project when considering all costs of the project including investment in natural gas infrastructure. For example, in the EPA's own "Documentation for Lateral Cost Estimation" the EPA references assume a $151/kW average for pipeline costs, but the EPA arbitrarily decides in its technical support document to use the *median* value of pipeline cost of $92/kW, undercutting that average cost by nearly 40%.[11]

Even with the cost included in this table, for many small entity utilities – such as electric cooperatives and municipal power utilities – that have large generating units that would be impacted by these regulations, the estimated cost would be devastating to their ability to compete in the market. For example, if AEPCO were to convert their other Apache Station coal boiler to natural gas, the pipeline company has told them that the capacity of the gas line is not adequate to supply both units. Therefore, they would more than likely have to purchase delivered natural gas, exposing them to market volatility in fuel pricing.

For many of those small entity utility plants, the costs in the table would increase the incremental cost of generation by 50% to 100%. This would remove the motivation to make the conversion, as the plant would run extraordinarily little at the higher price.

Conclusion

The EPA's proposed rules do not contain practical options for converting current coal generation capacity to natural gas-firing. The evidence provided in this document identifies problems with design considerations, general availability, cost of conversion, cost of operation and adverse weather reliability. These factors will negatively impact the already tenuous condition of generating resources on the electricity grid.

About the Authors

Dr. William Morris, Carbon Management Strategies, LLC

Dr. William Morris completed his Ph.D. and M.S. in chemical engineering at the University of Utah, examining the effect of pollutants such as NO_X, SO_X, and particulate matter on aerosol formation in air and oxy-fired combustion for CO_2 capture. He also holds a coordinate A.B. in Physics and Environmental Studies, with a minor in History from Bowdoin College. He is currently president and technical director of Carbon Management Strategies LLC. He is also contracted by the Wyoming Energy Authority (WEA) as Program Director to provide

[11] U.S. Environmental Protection Agency. Office of Air and Radiation. *Documentation for Lateral Cost Estimation.* April 2023. Available here: https://downloads.regulations.gov/EPA-HQ-OAR-2023-0072-0061/attachment_11.pdf

engineering and business development support services for CO_2 management technologies testing at the Wyoming Integrated Test Center (ITC). The ITC facility is a public/private venture between Basin Electric Power Cooperative, Tri-State G&T, the National Rural Electric Cooperative Association, Black Hills Power, and the state of Wyoming through the Wyoming Infrastructure Authority. The research facility can provide up to 23 MW equivalent of flue gas for large pilot post combustion CO_2 capture testing, as well as 6 small 0.4 MWe test bays which have hosted the NRG COSIA Carbon XPRIZE CO2 utilization competition as well as a post combustion capture system from TDA Research. Additional projects in the procurement phase are Kawasaki Heavy Industries solid adsorbent technology, Membrane Technology and Research's 180 tonne per day membrane CO_2 capture facility, and another 24 ton per day membrane capture system led by Gas Technology Institute and the Ohio State University.

As an employee of ADA Environmental Solutions, Dr. Morris worked in the areas of mercury emissions control, CO_2 capture, NO_X control, and is the listed inventor on 3 issued NO_X, mercury, and CO_2 emissions control patents, as well as other patents pending. He was also a contributing author to the oxy-fuel combustion section of the National Coal Council's report, *Fossil Forward,* in 2015 for then Department of Energy Secretary of Energy, Ernest Moniz, providing an update on CO_2 capture technologies. In addition, he was the CO_2 use chapter co-lead with Professor Alissa Park of Columbia University for the National Petroleum Council's report, *Meeting the Dual Challenge - A Roadmap to At-Scale Deployment of Carbon Capture, Use, and Storage*. He has conducted basic research, small pilot research, and commercial scale demonstrations and trials of various mercury, NO_X, and emissions control technologies with both private industry and universities. Commercialization success included developing a novel coal treatment process to qualify for the IRS section 45 refined coal tax credit, which produced approximately $1.8 billion in tax credits. Previous partners have included University of Utah, University of California Berkeley, Texas A&M University, Lehigh University, Southern Company, Aspen Aerogels, The University of Akron, the Electric Power Research Institute, the National Energy Technology Laboratory, the U.S. Department of Energy, and other private industry companies. In addition, he has been a peer reviewer for the journals of American Chemical Society as well as Elsevier Publishing.

Mr. John Weeda, Quail Hollow, LLC

John Weeda is a professional engineer (retired) with a long history of startup, operation, and maintenance of large generating plants and ethanol production facilities. Over the years, he served in roles of engineer, engineering management, plant management, operations director, and interim CEO and board member. The facilities that Mr. Weeda worked in and was responsible for included nuclear fuel, lignite, sub bituminous, and combined heat and power. The organizations that he worked with pioneered and patented several new technologies. The largest of these is a coal drying technology that has dried more lignite than any other technology in the world. The ethanol facilities that Mr. Weeda was involved in developing pioneered the use of waste heat in the ethanol production process and are a major supply of low carbon ethanol to the low carbon fuels market.

During his career, Mr. Weeda has worked closely with other organizations, such as the Electric Power Research Institute, to research and adopt technology to the power industry that brought

improved efficiency and environmental performance from demonstration to commercialization. The facilities that he was responsible for recognized that success in operation was driven by success in the marketplace. This applied to both the products that were offered and the price of the products competing against others in the market. A good example of that is taking the fly ash from being a waste product to being a product that is specified by name in the civil specifications for many civil projects in the region.

In recent years, Mr. Weeda applied that background in generation and markets to the electric grid. In the North Dakota Transmission Authority role, he emphasized the need for North Dakota to get their product to market with adequate transmission, emphasizing the clean energy role that North Dakota plays in that market and to be a leading state in having "all of the above" energy resources working together for the benefit of the country.

Mr. Weeda was an active cooperative member of NRECA for many years and, now as a consultant with NRECA, John has helped bring information to the membership that will keep their generation resources viable in the changing energy environment they are facing.

Attachment L

COMMENTS OF THE POWER GENERATORS AIR COALITION ON EPA'S PROPOSED RULE ENTITLED "ADOPTION AND SUBMITTAL OF STATE PLANS FOR DESIGNATED FACILITIES: IMPLEMENTING REGULATIONS UNDER CLEAN AIR ACT SECTION 111(D)"

87 Fed. Reg. 79,176 (Dec. 23, 2022)

Docket ID No. EPA-HQ-OAR-2021-0527

The Power Generators Air Coalition ("PGen") respectfully submits these comments to the U.S. Environmental Protection Agency ("EPA" or "the Agency") on its proposed rule entitled "Adoption and Submittal of State Plans for Designated Facilities: Implementing Regulations Under Clean Air Act Section 111(d)," which was published in the Federal Register on December 23, 2022 (hereinafter, "Proposed Rule").[1] The Proposed Rule proposes to amend the regulations governing implementation of emission guidelines under section 111(d) of the Clean Air Act ("CAA" or "the Act").

I. Background

PGen is an incorporated nonprofit 501(c)(6) organization whose members are diverse electric generating companies—public power, rural electric cooperatives, and investor-owned utilities—with a mix of solar, wind, hydroelectric, nuclear, and fossil generation. PGen is a collaborative effort of electric generators to share information and expertise in the interest of effectively managing air emissions to meet and exceed environmental laws and regulations and in the interest of informing sound regulation and public policy.[2] Our members include leaders in the fundamental transition to cleaner energy that is currently occurring in the industry. PGen as an organization does not participate in legislative lobbying or litigation. PGen and its members work to ensure that environmental regulations support a clean, safe, reliable, and affordable electric system for the nation.

PGen members own and operate fossil fuel-fired electric generating units ("EGUs"), as well as renewable resources like wind and solar. Greenhouse gas ("GHG") emissions from new, modified, and reconstructed fossil fuel-fired EGUs are regulated under section 111(b) of the CAA. Because GHGs are neither a criteria air pollutant under the Act's national ambient air quality standards ("NAAQS") program nor regulated as a hazardous air pollutant under section 112 of the Act, GHG emissions from existing fossil fuel-fired EGUs owned and operated by PGen members will be subject to regulation under section 111(d). As such, PGen has an interest in the Proposed Rule.

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[1] 87 Fed. Reg. 79,176 (Dec. 23, 2022).

[2] Additional information about PGen and its members can be found at https://pgen.org/.

EPA's proposed revisions to the section 111(d) implementing regulations are important. While historically section 111(d) has been invoked only rarely,[3] EPA's regulation of GHGs will lead to this provision being invoked much more frequently and for a broad spectrum of source categories given the ubiquitous nature of carbon dioxide ("CO_2") (a GHG) emissions. EPA recently proposed a section 111(d) emission guideline rule to regulate methane (another GHG) emissions from existing sources in the oil and natural gas sector,[4] and has announced plans to release a proposed rule regulating GHG emissions from fossil fuel-fired EGUs under section 111(d) in the next few months. PGen has been working with EPA regarding how best to regulate CO_2 emissions from existing EGUs, including meeting with EPA in November 2022, and submitting comments to EPA's pre-proposal non-rulemaking docket in December 2022.[5]

As part of the Affordable Clean Energy Rule,[6] EPA amended its section 111(d) implementing regulations to promulgate a new Subpart Ba of 40 C.F.R. part 60, which would apply to any emission guidelines issued after July 18, 2019. The original section 111(d) implementing regulations are promulgated as Subpart B and apply to emission guidelines issued before that date. Part of the Subpart Ba amendments included changing the deadlines for submittal and approval of state plans (and where necessary promulgation of federal plans) to align them with the deadlines in section 110 of the CAA for state implementation plans ("SIPs") under the NAAQS program. This aspect of the Subpart Ba regulations was challenged in the U.S. Court of Appeals for the D.C. Circuit. The court vacated the extensions of the compliance periods contained in Subpart Ba because it found that EPA had failed to adequately explain why the extensions were needed and because it further found that EPA had failed to address what the public health and environmental effects would be from the extension of the compliance periods.[7] The Proposed Rule proposes new timing provisions for Subpart Ba in response to the court's decision.

As an initial threshold matter, it is important for EPA to recognize that Congress limited its role under section 111(d). Unlike section 111(b) of the Act where EPA controls all aspects of a performance standard for new and modified sources in a source category, section 111(d) is a state-driven program. Under section 111(d), it is the states that "establish[] standards of performance for any existing source … to which a standard of performance … would apply if such existing source were a new source."[8] EPA must allow the state "in applying a standard of performance to any particular source under a plan … to take into consideration, among other

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[3] *See* 87 Fed. Reg. at 79,179.

[4] 87 Fed. Reg. 74,702 (Dec. 6, 2022).

[5] Comments of the Power Generators Air Coalition to EPA's Pre-Proposal Non-Rulemaking Comments on Reducing Greenhouse Gas Emissions from New and Existing Fossil Fuel-Fired Electric Generating Units, Docket ID No. EPA-HQ-OAR-2022-0723-0031 (Dec. 22, 2022) (hereinafter, "Pre-Proposal Comments").

[6] 84 Fed. Reg. 32,520 (July 8, 2019).

[7] *Am. Lung Ass'n v. EPA*, 985 F.3d 914, 991-95 (D.C. Cir. 2021).

[8] CAA § 111(d)(1), 42 U.S.C. § 7411(d)(1).

factors, the remaining useful life of the existing source to which such standard applies."[9] EPA has oversight authority and determines whether a state plan is "satisfactory."[10] If a state fails to submit a satisfactory plan, then EPA puts in place a federal plan and *must* take into consideration the remaining useful life of the source, among other factors ("RULOF").[11] In promulgating these implementation regulations for section 111(d), EPA should be careful to honor the cooperative federalism approach set out by Congress and not encroach on the states' authority. Further, states should be afforded adequate time to develop their state plans, aligned with the state's rulemaking process.

PGen offers the following specific comments on the Proposed Rule.

II. While EPA Acknowledges More Time Is Needed and Attempts to Rectify this Issue, Several of the Timing Provisions Set Forth in the Proposed Rule Do Not Provide Sufficient Time, Are Unrealistic Based on Evidence in the Record, and Will Result in Missed Deadlines.

A. The D.C. Circuit's decision in *American Lung Association v. EPA* does not foreclose longer timelines than those proposed.

It is important to note at the outset that the D.C. Circuit did not hold that the previous timing deadlines under the Subpart Ba implementation regulations were *per se* unlawful. Rather, the court said that EPA had failed to provide an adequate explanation for why the longer timing deadlines were needed (particularly given the fact that a state plan under section 111(d) is "simpler" and of a "different scale" than a SIP) and had failed to examine at all the public health and welfare implications of the longer deadlines.[12]

EPA has included empirical evidence in the preamble to the Proposed Rule that demonstrates that longer deadlines are needed. Indeed, as discussed further below, that empirical evidence shows that some of the deadlines in the Proposed Rule need to be longer to avoid missed deadlines. EPA needs to ensure that the deadlines that it sets are realistic and can be met. If deadlines are missed, this only further delays implementation of the program because the clock resets for EPA to promulgate a federal plan. As EPA acknowledges, "[a]llowing states sufficient time to develop feasible implementation plans for their designated facilities … *ultimately helps* ensure more timely implementation of an [emissions guideline], and therefore *achievement in*

[9] *Id.*

[10] *Id.* § 111(d)(2)(A), 42 U.S.C. § 7411(d)(2)(A).

[11] *Id.* § 111(d), 42 U.S.C. § 7411(d).

[12] *Am. Lung Ass'n*, 985 F.3d at 991-93.

actual emission reductions, than would an unattainable deadline that may result in the failure of states to submit plans and requiring the development and implementation [of a] Federal plan."[13]

To ensure emission reductions are achieved in a timely manner, EPA should extend some of the deadlines in the Proposed Rule, as discussed in further detail below.

B. The proposed deadline for state plan submissions is too short and will be missed, particularly given the increased requirements associated with state plan preparation. (Comments A1-1, A1-2, A1-3, A1-4, and A1-5)

EPA proposes to give states 15 months to submit state plans under section 111(d) unless EPA specifies otherwise in the emissions guideline.[14] EPA provides evidence in the preamble to the Proposed Rule that shows that 15 months is not sufficient and that more time is needed. In the preamble, EPA appropriately examines the time it takes for states to submit plans under section 129 of the CAA.[15] Section 129 plans are very similar to section 111(d) plans, but section 111(d) plans "involve more complicated analyses" because of the fact that section 111(d) allows states to take RULOF into account.[16] EPA is proposing new requirements for states that choose to propose a less stringent standard for a designated facility based on RULOF, and these new requirements will add more time to the state's preparation of a plan. EPA notes that states take on average between 14 to 17 months after publication of an emissions guideline to prepare a state plan under section 129.[17] Given that plans under section 111(d) "permit[] more source-specific analysis," which takes more time, it is clear that 15 months does not provide sufficient time.

In addition to the individualized, source-specific analysis of RULOF that results in a section 111(d) plan taking more time than a section 129 plan, EPA is proposing to add significant new requirements for outreach and engagement.[18] Under the current regulations, a state must hold a public hearing prior to adopting a state plan.[19] In contrast, under the Proposed Rule, a state would be required to "conduct meaningful engagement" with pertinent stakeholders.[20] Meaningful engagement encompasses much more than the current requirement for a public hearing, including "the development of public participation strategies" and "early outreach, sharing information, and soliciting input on the state plan."[21] Depending on the number

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[13] 87 Fed. Reg. at 79,183 (emphases added).

[14] Proposed 40 C.F.R. § 60.23a.

[15] 87 Fed. Reg. at 79,183.

[16] *Id.*

[17] *Id.*

[18] *Id.* at 79,190-92; Proposed 40 C.F.R. § 60.23a(i).

[19] 40 C.F.R. § 60.23a(c).

[20] Proposed 40 C.F.R. § 60.23a(i)(1).

[21] *Id.* § 60.21a(k).

of communities that might be affected by the state plan,[22] this outreach could be a significant effort on the part of the states. Because of these new community engagement requirements and the new requirements for states that wish to undergo a RULOF analysis, additional time is needed to ensure that the states can realistically meet the deadline. The proposed time of 15 months simply is insufficient.

States may also have unique procedures that could further lengthen the time they need.[23] For example, some states require a state plan to be approved by the state legislature, and many state legislatures meet only for a few months a year. Depending on when in the legislative cycle a state plan is completed and ready for state legislative review, it may be several months before the legislature is back in session. This provides yet more justification for why additional time is needed for states to submit plans.

In the Proposed Rule, EPA compares state plan preparation under section 111(d) to preparation of attainment plans for the 2012 $PM_{2.5}$ NAAQS, which had a statutory deadline of 18 months from the date an area was designated nonattainment.[24] EPA fails to acknowledge, however, that states have *much* more notice that they have an area that is nonattainment long before the area is formally designated nonattainment. Looking at the complete timeline for the 2012 $PM_{2.5}$ NAAQS shows the true amount of time states have to prepare attainment SIPs. The 2012 $PM_{2.5}$ NAAQS were finalized on January 15, 2013.[25] At that point, states had notice that they may have areas that are not in attainment with the NAAQS. Indeed, the Governors of each state have to submit initial designations regarding attainment of a NAAQS within one year of a NAAQS being promulgated.[26] EPA finalized the designations for the 2012 $PM_{2.5}$ NAAQS for most areas on January 15, 2015—*two years* after the NAAQS were finalized—and those designations became effective on April 15, 2015.[27] The 18-month time period for states to submit their attainment SIPs that EPA references in the Proposed Rule[28] began to run on that effective date (i.e., April 15, 2015). In examining how long a state has to prepare attainment SIPs, EPA needs to account for all the time leading up to the running of the 18-month clock where the state had notice that they had a nonattainment area. In this case, that was a period of *27 months* (January 15, 2013, to April 15, 2015), bringing the total amount of time the states had to prepare attainment SIPs to *45 months* (i.e., nearly four years).[29] In contrast, with regard to

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[22] *See id.* § 60.21a(l).

[23] 87 Fed. Reg. at 79,182 n.9 (acknowledging "[i]n many states, the agency must submit its rule to a particular independent commission or the legislature for review and approval before the rule is finally adopted").

[24] *Id.* at 79,183.

[25] 78 Fed. Reg. 3086 (Jan. 15, 2013).

[26] CAA § 107(d)(1)(A), 42 U.S.C. § 7407(d)(1)(A).

[27] 80 Fed. Reg. 2206 (Jan. 15, 2015).

[28] 87 Fed. Reg. at 79,183.

[29] Even if one assumes that the state did not have notice that it had a nonattainment area at the time the NAAQS was finalized, it is absolutely true that the state knew a year later when the

state plan submission under section 111(d), there is not a period of years where a state knows what it is going to have to do before the clock begins to run. A state does not know what EPA's determination of the BSER and the resulting presumptive level of stringency is until the final emissions guideline is issued.

In its Pre-Proposal Comments, PGen suggested that a minimum of two years is needed for submission of state plans from the time of publication of a final emissions guideline.[30] Since that time, however, PGen has seen that states are saying that even more time than two years is needed, and PGen respectfully suggests that EPA defer to the states regarding how much time is needed for state plan submission as they are in the best position to know what is involved in preparing a plan. For example, the State of Tennessee recently said in its comments on EPA's proposed section 111(d) emissions guideline for the oil and gas sector that given the new requirements for RULOF and community engagement that it needed 30 months to prepare its state plan.[31]

As discussed above, the D.C. Circuit's decision in *American Lung Association v. EPA* did not foreclose the current deadlines; rather, EPA must provide a better explanation for why that amount of time is needed. As further discussed above, the evidence provided by EPA in the preamble to the Proposed Rule demonstrates that the proposed time of 15 months is insufficient.

C. PGen supports the proposed 60-day limit for EPA to determine completeness of state plans. (Comment A2-1)

PGen generally supports EPA's proposal to require EPA to determine whether a state plan is complete within 60 days after receipt of the plan. Under the Proposed Rule, a state plan would be deemed automatically complete by operation of law if EPA misses this deadline.[32] As EPA notes, the completeness determination is a "ministerial" one that "requires no exercise of discretion or judgment on the Agency's part."[33]

PGen is concerned, however, that a state plan that is automatically deemed complete by operation of law could later be disapproved by EPA because it is missing something that should have been caught during the completeness determination process. This would unfairly impact the state because the clock for a federal plan would start ticking. The state should not be penalized for making a mistake that should have been caught during the completeness determination

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Governor made the initial designations. That still provided the state with 33 months to prepare and submit its attainment SIP, which is far more than the 18 months EPA references in the Proposed Rule.

[30] Pre-Proposal Comments at 15.

[31] Tennessee Comments on Proposed Standards of Performance for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Oil and Natural Gas Sector Climate Review at 6, Docket ID No. EPA-HQ-OAR-2021-0317-2157 (Feb. 7, 2023).

[32] Proposed 40 C.F.R. § 60.27a(g)(1).

[33] 87 Fed. Reg. at 79,184.

process, and if the only reason a state plan would face disapproval is because it is missing something that should have been caught during that review, the state should be given a reasonable period of time to cure the defect before the plan is disapproved and before the federal plan clock begins to run.

D. EPA does not appear to be giving itself enough time to act on state plans based on the evidence in the record. (Comment A3-1)

Under the Proposed Rule, EPA proposes to give itself 12 months after a state plan is determined to be complete (either by EPA or by operation of law) to determine whether the plan is "satisfactory." PGen notes that based on the evidence presented in the preamble to the Proposed Rule, this timeline appears to be unrealistic. EPA provides the following timelines and steps for the Agency to make a determination that a state plan is satisfactory:

- First, EPA has to evaluate a state plan, draft a proposed action on the plan, and have that proposed action edited, reviewed, and signed. According to EPA, this typically takes between 6 to 8 months.[34]
- Second, the proposed action needs to be published in the Federal Register, which EPA says can take several weeks of processing.[35]
- Third, the public must be given at least 30 days to comment on the proposed action, and this might be extended if requested.[36]
- Fourth, EPA has to review the comments, prepare updated recommendations for review, consult with agency decision makers, prepare a final rule, prepare a response to comments document and any necessary record support, and possibly prepare proposed regulatory text. EPA says this typically takes between 4 to 7 months.[37]

Assuming the *average* amount of time under these estimates, it is apparent that the 12-month deadline is unrealistic: 7 months for step one + 0.5 months to publish in the Federal Register + 1 month for public comment + 5.5 months to prepare final rule = 14 months. Only the *best-case scenario* might make this deadline (meaning everything happens at the low end of EPA's estimates and the rule is published in the Federal Register within one week): 6 months for step one + 1 week to publish + 1 month for comment + 4 months to finalize the rule = 11.25 months. It is unlikely that the review of every state plan can meet the high hurdle of the best-case scenario.

PGen suggests that EPA consider giving itself more time to ensure that it has adequate time to review state submissions. This is far preferable to the current proposal, which sets the

[34] *Id.* at 79,185.

[35] *Id.*

[36] *Id.*

[37] *Id.* at 79,185-86.

Agency up to miss a deadline—or worse puts EPA in a position where it needs to rush to meet an unreasonable deadline and acts in a less than thorough manner. PGen suggests that EPA consider setting a deadline for itself between 14 months (the average scenario) and 18 months (a scenario on the longer side of the estimates).[38]

E. EPA should ensure it has sufficient time to consider remaining useful life, as is required under the CAA, when it is promulgating a federal plan. (Comment A4-1)

PGen is concerned that EPA has not provided itself with sufficient time to consider RULOF when it is promulgating a federal plan. EPA has proposed to give itself 12 months to promulgate a federal plan after either: (a) a state fails to submit a state plan by the deadline; or (b) EPA disapproves a state plan because it fails to meet the "satisfactory" standard.[39] EPA needs to ensure that it gives itself enough time to consider RULOF in its preparation of a federal plan. Unlike states where this consideration is optional, Congress *requires* EPA to take RULOF into account.[40] Particularly given the proposed additional requirements around RULOF, EPA needs to ensure it has enough time to conduct this important analysis.

As previously stated with regard to EPA's review and action on state plans, EPA should not set itself up for failure. Rushing to meet an unreasonable deadline will not result in a federal plan that considers all affected facilities in a meaningful way, including RULOF. EPA provides the following timelines and steps for the Agency to promulgate a federal plan:

- First, EPA has to form an intra-agency workgroup that develops recommendations for the components of the federal plan, including determining the standards of performance for designated facilities that generally reflect the presumptive level of stringency of the emissions guideline, including possible adjustments based on RULOF, any testing, monitoring, reporting, and recordkeeping requirements, and that complies with the meaningful engagement requirements of the Proposed Rule. The recommended components of the federal plan are reviewed and then a proposed federal plan is drafted, along with a technical support document. The proposed federal plan is then reviewed by the relevant EPA offices and signed. According to EPA, this step typically takes "a minimum" of 6 to 9 months.[41]

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[38] The scenario based on the longer side of the estimates is calculated as follows: 8 months for step one + 1 month to publish in the Federal Register + 2 months for public comment + 7 months to prepare final rule = 18 months.

[39] Proposed 40 C.F.R. § 60.27a(c).

[40] CAA § 111(d)(2), 42 U.S.C. § 7411(d)(2) (noting "the Administrator *shall* take into consideration, among other factors, remaining useful lives of the sources in the category of sources to which a standard applies") (emphasis added).

[41] 87 Fed. Reg. at 79,187-88.

- Second, the proposed federal plan needs to be published in the Federal Register, which EPA says can take several weeks of processing.[42]
- Third, notice of at least 15 days must be given for a public hearing where members of the public can submit oral comments on the proposed federal plan, and notice of at least 30 days must be given for submission of written comments on the proposed federal plan. Because of the public hearing requirement, EPA says it "should allow for at least 45 days for public comment."[43]
- Fourth, EPA has to review the comments, prepare updated recommendations for review, consult with agency decision makers, prepare a final federal plan, prepare a response to comments document and any necessary record support, and prepare proposed regulatory text. EPA says this typically takes between 4 to 8 months.[44]

Assuming the *average* amount of time under these estimates, it is apparent that the 12-month deadline is unrealistic: 7.5 months for step one + 0.5 month to publish in the Federal Register + 1.5 months for public comment and public hearing + 6 months to prepare final rule = 15.5 months. Only the *best-case scenario* might make this deadline (meaning everything happens at the low end of EPA's estimates and the rule is published in the Federal Register within one week): 6 months for step one + 1 week to publish + 1.5 months for comment and public hearing + 4 months to finalize the rule = 11.75 months. It is unlikely that the preparation of a federal plan will always be able to meet the aggressive timelines of a best-case scenario.

PGen suggests that EPA consider giving itself more time to ensure that it has adequate time to promulgate a federal plan so that it does not set itself up to miss a deadline—or worse rush to meet an unreasonable deadline and set itself up for a legal challenge that it failed to adequately consider RULOF or another requirement. PGen suggests that EPA consider setting a deadline for itself between 16 months (the average scenario) and 20 months (a scenario on the longer side of the estimates).[45]

F. The timeline for increments of progress should run from EPA's approval of a state plan—not from the state plan submission deadline. (Comment A5-1)

PGen believes that it is reasonable to require states to show increments of progress when a compliance schedule for a state plan is going to extend more than 16 months.[46] PGen is concerned, however, with connecting the timing of the increments of progress to the state plan submission deadline. States should not be required to begin implementation on a state plan until

[42] *Id.* at 79,185, 79,188.

[43] *Id.* at 79,188.

[44] *Id.*

[45] The scenario based on the longer side of the estimates is calculated as follows: 9 months for step one + 1 month to publish in the Federal Register + 2 months for public comment and public hearing + 8 months to prepare final rule = 20 months.

[46] Proposed 40 C.F.R. § 60.24a(d).

they know that EPA has approved it. As a result, the timing of increments of progress needs to be tied to the date EPA approves the plan—not the state plan submission deadline. EPA suggests that "[p]roviding a 2-month buffer after approval of plans but before the increments of progress are required allows for the owner or operator of designated facilities reasonable time to initiate actions associated with the increments of progress."[47] PGen believes that this does not provide a reasonable period of time.

Thus, PGen respectfully suggests that EPA require that state plans include increments of progress for any compliance schedule extending more than 16 months from EPA's *approval* of the plan.

G. EPA should continue to link the authority and timeline for a federal plan to a finding of failure to submit. (Comment B-1)

EPA proposes to revise the section 111(d) implementing regulations to link the 12-month clock for EPA to issue a federal plan to the missed state plan submission deadline—rather than what it is linked to now, which is a finding of failure to submit on the part of EPA.[48] As EPA notes, "a finding of failure to submit has value in notifying states and the public of the status of plans."[49] While the Agency says that it will still issue a finding of failure to submit, it says it will do so "anytime between the deadline for state plan submissions and the EPA's promulgation of a Federal plan."[50] The value of a finding of failure to submit is greatly diminished, however, the closer it occurs to the time a federal plan is issued, and is practically valueless if it occurs right before a federal plan is issued. The preparation and publication of a finding of failure to submit is not an onerous task that requires particular agency expertise or many man hours. There is no reason why this could not be done easily once the deadline has been missed.

EPA should not remove its own obligations and deadlines to issue a finding of failure to submit. The 12-month clock should continue to run from the publication of a finding of failure to submit.

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[47] 87 Fed. Reg. at 79,189.

[48] *Compare* Proposed 40 C.F.R. § 60.27a(c)(1) (requiring a federal plan be issued "after … [t]he State fails to submit a plan or plan revision within the time prescribed") *with* 40 C.F.R. § 60.27a(c)(1) (requiring a federal plan be issued "after the Administrator … [f]inds that a State fails to submit a required plan or plan revision").

[49] 87 Fed. Reg. at 79,190.

[50] *Id.*

III. EPA's Enhanced Requirements for Outreach and Meaningful Engagement Will Require States to Need More Time for State Plan Preparation, Could Strain Limited State Resources, and Need to Be More Clearly Defined if They Are Part of the Completeness Determination. (Comments C-1, C-2, and C-4)

EPA proposes significant new requirements for outreach by states to communities that are "most affected by and vulnerable to the impacts" of a state plan.[51] PGen agrees with EPA that public outreach, particularly with vulnerable communities, is valuable and worthwhile as a policy matter. EPA needs to consider, however, how these enhanced requirements add a layer of complexity to state plan development that will increase the time needed for states to submit state plans to EPA, and the Agency further needs to consider how these increased requirements may strain already limited state resources.

Under the current regulations, a state is simply required to hold a public hearing.[52] In contrast, the Proposed Rule would require states to "conduct meaningful engagement," with "pertinent stakeholders."[53] Pertinent stakeholders are defined to "include … industry, small businesses, and communities most affected by and/or vulnerable to the impacts of the plan or plan revisions."[54] In addition, meaningful engagement encompasses much more than the current requirement for a public hearing, including "the development of public participation strategies" and "early outreach, sharing information, and soliciting input on the state plan."[55] Depending on the number of communities that might be affected by the state plan, this outreach could be a significant effort on the part of the states (and can be even more time if the state invokes RULOF to propose a less stringent emission limitation for a designated facility).[56] All of these requirements, while laudable and good public policy, need to be accounted for in the amount of time that a state will need to prepare a state plan.

Under the Proposed Rule, as part of the completeness determination, a state plan must include "[e]vidence of meaningful engagement, including a list of pertinent stakeholders, a summary of the engagement conducted, and a summary of stakeholder input received."[57] EPA specifically asks for comment on whether evidence of meaningful engagement should be included in the completeness criteria.[58] PGen does not object in theory to the idea of meaningful engagement being part of the completeness analysis, but it does respectfully suggest that before this can be required that EPA needs to provide much more information to the states as to what exactly the state needs to do and what evidence it needs to provide in the state plan to be

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[51] *Id.*

[52] 40 C.F.R. § 60.23a(c).

[53] Proposed 40 C.F.R. § 60.23a(i)(1).

[54] *Id.* § 60.21a(l).

[55] *Id.* § 60.21a(k).

[56] *Id.* § 60.24a(k).

[57] *Id.* § 60.27a(g)(2)(ix).

[58] 87 Fed. Reg. at 79,192.

considered complete. The Proposed Rule as currently written is too vague, and states will be unsure of exactly what it is that they are required to do for a plan to be considered complete, leading to the determination of "completeness" potentially being overly subjective.

Finally, EPA's statement that meaningful engagement with pertinent stakeholders will "help ensure that plans achieve the appropriate level of emission reductions"[59] has no basis as a matter of law under the CAA. Under section 111(a)(1) of the Act, a standard of performance "reflects the degree of emission limitation achievable through the application of the [BSER]."[60] While meaningful engagement with the public and with vulnerable communities is generally good public policy, it does not have any bearing on the emission reductions that are achieved under section 111.

IV. EPA's Proposed Regulatory Mechanisms for State Plan Implementation (Comment D-1)

EPA is proposing to incorporate five regulatory mechanisms as amendments to the implementing regulations: (1) partial approval and disapproval of state plans; (2) conditional approval of state plans; (3) parallel processing of state plans; (4) a "state plan call"; and (5) error correction. PGen generally supports most of these proposed revisions, with the exception of the "state plan call" amendment.

Partial Approval and Disapproval (Comment D1-1). EPA proposes to revise the implementation regulations to add a provision similar to section 110(k)(3) of the CAA that would allow EPA to "partially approve or partially disapprove a state plan when portions of the plan are approvable, but a discrete, severable portion is not."[61] PGen supports this proposed revision.

Conditional Approval (Comments D2-1 and D2-2). EPA proposes to revise the implementation regulations to add a provision similar to section 110(k)(4) of the Act that would allow EPA to conditionally approve a state plan "that substantially meets the requirements of an [emissions guideline] but that requires some additional specified revisions to be fully approvable."[62] After conditional approval, a state would have one year to adopt and submit the necessary revisions to EPA. PGen supports this proposed revision and believes that one year is a sufficient amount of time for the state to submit the necessary revisions. Under the Proposed Rule, if a state failed to meet this one-year deadline, the conditional approval would automatically convert to a disapproval, which would begin the clock for EPA to issue a federal plan. PGen supports this proposed revision, but reiterates its concerns, expressed above in Section II.E., that the one-year period of time for EPA to promulgate a federal plan seems unrealistic based on the evidence EPA provides in the preamble to the Proposed Rule regarding how long it typically takes to issue a federal plan. Any deadline for a federal plan following a

[59] *Id.*

[60] CAA § 111(a)(1), 42 U.S.C. § 7411(a)(1).

[61] 87 Fed. Reg. at 79,193; *see also* 40 C.F.R. § 60.27a(b)(1).

[62] 87 Fed. Reg. at 79,193-94; *see also* 40 C.F.R. § 60.27a(b)(2).

conditional approval should match the amount of time generally given for EPA to promulgate such a plan.

Parallel Processing (Comments D3-1, D3-2, and D3-3). EPA proposes to revise the regulations "to include a mechanism similar to that for SIPs under 40 CFR part 51 appendix V, section 2.3.1., for parallel processing a plan that does not meet all of the administrative completeness criteria."[63] This provision would provide a state with additional time to complete its process to fully adopt the plan. PGen supports this proposed revision.

State Plan Calls (Comments D4-1, D4-2, D4-3, and D4-4). EPA proposes to add to the section 111(d) implementation regulations a provision similar to section 110(k)(5) that would allow EPA to call for revision of a state plan if EPA "find[s] that a previously approved state plan does not meet the applicable requirements of the CAA or of the relevant [emissions guideline]."[64] EPA notes that such an action "would be generally appropriate under two circumstances": (1) "when legal or technical conditions arise after the EPA's approval of a state plan that undermines the basis for the approval" (such as a subsequent court decision or design assumptions about control measures proving to be inaccurate); or (2) "a state fails to adequately implement an approved state plan."[65]

With regard to the first circumstance proposed by EPA (where legal or technical conditions arise that undermine the basis for EPA's approval), PGen believes that this situation can be rectified under the Error Correction provision that EPA proposes because the approval in these circumstances would have been "in error."[66]

With regard to the second circumstance proposed by EPA (where a state is failing to adequately implement an approved state plan), this situation is addressed directly in section 111(d)(2)(B) of the CAA, which specifies that EPA has "the same authority … to enforce the provisions of [a state] plan in cases where the State fails to enforce them as [the Administrator] would have under sections [113 and 114 of the CAA] with respect to an implementation plan."[67] Congress thus directed EPA not to call for a revision of a state plan, but instead to employ the federal enforcement measures set forth in sections 113 and 114 of the Act. This forecloses EPA from employing a "state plan call" to address a situation where a state plan is not being adequately implemented. For this reason, the proposed State Plan Call revision is unauthorized and should not be finalized.

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[63] 87 Fed. Reg. at 79,194.

[64] *Id.*

[65] *Id.* at 79,194-95.

[66] Proposed 40 C.F.R. § 60.27a(j).

[67] CAA § 111(d)(2)(B), 42 U.S.C. § 7411(d)(2)(B).

Error Correction (Comments D5-1 and D5-2)

As a general matter, PGen does not object to the proposed revisions that allow EPA to correct a situation where a plan was approved, disapproved, or promulgated in error.[68] This provision could be used in the event of a court decision that undermines the basis of an EPA decision on a state plan or to correct any typographical errors that might have occurred in a final rule. EPA should make clear in the regulations, however, that this provision cannot be used to effect a change in policy because of a change in perspective on implementation that may arise from an administration transition. Designated facilities need regulatory certainty, and the error correction provision should not be able to be used to radically change a designated facility's requirements.

V. EPA Should Be Careful Not to Unduly Limit the Discretion that Congress Gave States to Consider RULOF.

Congress directed that EPA's implementing regulations under section 111(d) "shall permit the State in applying a standard of performance to any particular source under a plan submitted [under section 111(d)] to take into consideration, among other factors, the remaining useful life of the existing source to which such standard applies."[69] While EPA has the authority to approve or disapprove of a state plan, it should not unduly limit a state's discretion to take RULOF into account. PGen generally supports EPA's proposed regulations regarding the steps that a state must take to apply a standard of performance to a designated facility that is less stringent than otherwise required by the emissions guideline based on RULOF.

A. EPA needs to be clear that if a state plan results in the same outcome in terms of environmental benefits that would have been achieved under EPA's presumptive level of stringency, that the RULOF provisions do not apply. (Comment E2-1)

PGen suggests that EPA make more clear that the RULOF provisions set forth in proposed § 60.24a(f) are required *only* when a state is proposing a less stringent emission standard for a designated facility, and these provisions do not apply if a state is achieving EPA's presumptive level of stringency through means other than the BSER identified by EPA. If a state plan results in the same outcome in terms of environmental benefits that would have been achieved under EPA's presumptive level of stringency, EPA needs to approve that state plan as "satisfactory." This conclusion is implied in the preamble to the Proposed Rule, which states that:

> [T]he proposed RULOF provisions … would apply where a state intends to *depart* from the presumptive standards in the [emissions guideline] and propose a less stringent standard … and not where a state intends to *comply* by demonstrating that a facility or group of facilities subject to a state program would, in the aggregate,

[68] Proposed 40 C.F.R. § 60.27a(j).

[69] CAA § 111(d)(1), 42 U.S.C. § 7411(d)(1).

> achieve equivalent or better reductions than if the state instead imposed the presumptive standards required under the [emissions guideline] at individual designated facilities.[70]

This conclusion is further implied in the proposed § 60.24a(g), which says that a state "may not apply a less stringent standard in cases where a designated facility can reasonably implement a technology or other system of emissions reduction other than one identified as the [BSER] to achieve the degree of emission limitation required by an emission guideline."[71]

To avoid any potential confusion on this point, EPA should be clear in the preamble to the final rule that the RULOF provisions are required *only* when a state is proposing a less stringent emission standard for a designated facility—not when a state is achieving EPA's presumptive level of stringency through means other than the BSER identified by EPA.

B. PGen supports EPA's revisions that would allow for operational conditions based on remaining useful life or restricted operating capacity as a basis for setting a less stringent standard. (Comment E5-1)

PGen agrees with EPA's proposed approach for contingency requirements that would allow a state to invoke RULOF on the basis that a source "is running at lower utilization … than is anticipated by the BSER and intends to do so for the duration of the compliance period…."[72] As PGen stated in its Pre-Proposal Comments, existing fossil fuel-fired EGUs that operate rarely should be allowed to comply with alternative emission limitation requirements, and "[t]hese units could be subject to limitations on the amount they may operate in a given year."[73] There may be important reliability reasons why an electric generator may want to keep open a plant that is used rarely. Companies will not be willing to invest large sums in such a unit. Allowing states to invoke RULOF to allow for a less stringent standard for these facilities makes good sense.

PGen also agrees with the Proposed Rule's requirement that where a state plan contains a less stringent emissions limitation for a designated facility based on RULOF "on the basis of an operating condition(s) within the designated facility's control, such as remaining useful life or restricted capacity, the plan must also include such operating condition(s) as an enforceable requirement."[74] PGen also agrees with the approach where a state may change its plan in the future to address changes in operating conditions.[75]

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[70] 87 Fed. Reg. at 79,198 (emphasis in original).

[71] Proposed 40 C.F.R. § 60.24a(g).

[72] 87 Fed. Reg. at 79,200.

[73] Pre-Proposal Comments at 7.

[74] Proposed 40 C.F.R. § 60.24a(h).

[75] 87 Fed. Reg. at 79,201 (noting "a state may submit a plan revision to reflect [a] change in operating conditions" and "[s]uch a plan revision must include a new standard of performance that accounts for the change in operating conditions").

C. PGen generally supports EPA's proposal regarding how retirements may factor into state plans. (Comment E6-1)

EPA proposes to allow states to apply a less stringent standard on the grounds that a designated facility will retire within a period of time identified by EPA or determined by the states through a methodology provided by EPA.[76] PGen supports this proposal. As PGen said in its Pre-Proposal Comments, states should be permitted to provide alternative, less-stringent emission limitation requirements in their state plans for fossil fuel-fired EGUs that will retire within a reasonable amount of time.[77] PGen appreciates that EPA has made clear that "[i]f a designated facility's retirement date is both imminent and prior to the outermost retirement date identified in an emission guideline, the plan may apply a standard that reflects the designated facility's business as usual."[78]

As EPA knows, the electric generation industry is undergoing a transition away from fossil fuel-fired generation. As a result, many EGUs may not operate until their useful lives have expired, and EPA's Proposed Rule adequately takes that into account. States should be able to require less from units that are not expected to operate much longer under their consideration of RULOF. Owners and operators will not want to put significant monetary resources into units that will not be operating in the near future. If required to do so, these units may be prematurely retired, and this could have significant impacts on electric reliability.

In the Proposed Rule, EPA proposes to establish a date or a methodology for determining what announced retirement dates will qualify for alternative emission limitation requirements in an emissions guideline. PGen asks EPA in setting any retirement deadline for EGUs in its upcoming proposed emissions guideline for fossil fuel-fired EGUs to consider other statutes and regulations that may be driving retirements, such as EPA's Effluent Limitations Guidelines for fossil fuel-fired EGUs. EPA should coordinate the deadlines in these other rules with the outer limit that it establishes for retirements under section 111(d).

VI. PGen Supports EPA's Proposed Revisions to Change the Definition of Standard of Performance and to Allow Compliance Flexibility.

EPA proposes to revise the section 111(d) implementation regulations "to clarify that the definition of 'Standard of performance' allows for state plans to include standards in the form of an allowable mass limit of emissions."[79] PGen supports this proposed change. As PGen said in its Pre-Proposal Comments, "EPA should allow a state to express the emissions limits as a mass-based emission rate (e.g., tons of CO_2 per year)…."[80]

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[76] Proposed 40 C.F.R. § 60.24a(i).

[77] Pre-Proposal Comments at 7.

[78] Proposed 40 C.F.R. § 60.24a(i)(2).

[79] 87 Fed. Reg. at 79,206.

[80] Pre-Proposal Comments at 16.

PGen also agrees with and supports EPA's proposed reversal of its prior interpretation of section 111(d) that prohibited compliance flexibilities, including emissions averaging and trading.[81] States should be permitted to allow emissions averaging, trading, and other flexible measures to aid owners and operators of designated facilities in complying with emissions limitations established under section 111(d). As EPA noted when it proposed the Clean Air Mercury Rule, the Agency's "significant experience" with cap-and-trade programs for utilities has shown that such programs cause emissions to fall *below* the mandated cap, despite increased electric generation, while "maximizing overall cost-effectiveness."[82]

Ensuring that states have maximum flexibility in terms of compliance strategies will result in another significant benefit: electric reliability. As PGen noted in its Pre-Proposal Comments, "[a] trading program will allow fossil fuel-fired EGUs that are rarely used to continue to be operated for the purpose of stabilizing the grid during times of peak load (such as during times of extreme heat or cold or because of an extreme weather event)…."[83] As further discussed in PGen's comments, flexible compliance tools such as emissions trading or averaging have been shown to result in significant benefits to environmental justice communities.[84]

* * *

PGen appreciates the opportunity to comment on EPA's Proposed Rule. If EPA has any questions on PGen's comments, or if EPA would like to meet with PGen members to discuss these comments further, it should contact PGen's counsel below, who will work with PGen's Board of Directors to arrange a convenient time.

Dated: February 27, 2023

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[81] 87 Fed. Reg. at 79,207-08.

[82] 69 Fed. Reg. 4652, 5697 (Jan. 30, 2004); *see also id.* (noting that trading "maximizes the cost-effectiveness of the emissions reductions in accordance with market forces" and that "[s]ources have an incentive to endeavor to reduce their emissions below the number of allowances they receive").

[83] Pre-Proposal Comments at 10.

[84] *Id.* at 10-15 (Section VI).

Attachment M

FINAL REPORT

Technical Comments on the U.S. Environmental Protection Agency's Integrated Planning Model's Evaluation of the Greenhouse Gas Standards and Guidelines for Fossil Fuel-fired Power Plants – Proposed Rule

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August 7, 2023

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1 SUMMARY

The following summarizes the major issues and flaws of the U.S. Environmental Protection Agency's (EPA) modeling using the Agency's Integrated Planning Model (IPM) of the proposed rule and they are:

- EPA's Updated Baseline is an outlier, when compared to other model forecasts of the electric power sector due to EPA's unrealistically "optimistic" interpretation of the Inflation Reduction Act; whereby, EPA fails to understand and properly consider grid reliability in 2028 and 2030.

- EPA fails to understand and properly consider those issues confronting RTOs and electric utilities during this transition from dispatchable fossil sources to non-dispatchable, intermittent generating sources.

- EPA's Updated Baseline is flawed based upon erroneous coal retirements and retrofitted CCS units in 2030.

2 INTRODUCTION

On May 11, 2023, the U.S. Environmental Protection Agency (EPA) announced proposed new standards and guidelines for greenhouse gas emissions from coal and gas-fired power plants. As a part of this rulemaking effort, EPA modeled the estimated impacts this proposed rule would have upon the electric power sector using its Integrated Planning Model (IPM). These modeling results appear in the Regulatory Impact Analysis (RIA), which accompanied the proposed rule announcement. However, on July 7, 2023 EPA issued "updated" IPM modeling runs which resulted in an Updated Baseline and a new Integrated Proposal (Policy Case) for the proposed rule. It is these two new modeling runs that are evaluated in this report.

3 IPM'S MODELED UPDATED BASELINE IS AN OUTLIER

This discussion presents a general overview of various models used to project public policy impacts on the electric power sector, specifically as they apply to environmental regulations. The focus here, is to compare and discuss in general terms how the results from EPA's Integrated Planning Model (IPM) compares to other models in predicting policy impacts on the electric power sector. Depending on available information, some models present more data than others. One of the major points of evaluation is to see how the Inflation Reduction Act (IRA) was handled by each model and how it impacts the future generating capacity levels in the electric power sector and the potential impacts on grid reliability, specifically in the years 2028 and 2030.

The Base/Reference Cases, that are illustrated in Appendix 3.0, represent modeled outputs that includes the IRA and various environmental regulations. In addition, to evaluating the impacts of the IRA on the electric power sector, there is also an IPM simulation of the Integrated Proposal (i.e., proposed GHG Emission Standard and Guidelines) on the electric power sector.

3.1 Overview of Models

As mentioned above, the primary focus was comparing model results from IPM to other models used in evaluating public policy impacts on the electric power sector. Those models are as follows:

- EPA's IPM – IPM is EPA's principal modeling tool to evaluate economic and compliance impacts on the electric power sector. Two modeling scenarios were evaluated: (i) Pre-IRA 2022 Reference Case (January 2023); and, (ii) Post-IRA 2022 Reference Case (March 2023). The Pre-IRA 2022 Reference Case was used in modeling the compliance and economic impact of the proposed Effluent Limitation Guidelines (ELG) rule, published on March 29, 2023, while the Post-IRA 2022 Reference Case, which is the Updated Baseline, was used in modeling the economic and compliance impacts of the proposed MATS Residual Risk and Technology Review (RTR) and Carbon Standard. Both IPM reference cases use the Energy Information Administration's (EIA) Annual Energy Outlook (AEO) 2021 to forecast future electrical demand.[1]
- EIA's National Energy Modeling System (NEMS) – NEMS is an economy-wide modeling system that EIA uses in its annual AEOs. For this analysis, *AEO 2023's Reference Case* (March 2023) modeling of the electric power sector was evaluated, which included the IRA.[2]

[1] Information on IPM can be found at www.epa.gov/power-sector-modeling
[2] Information on NEMS can be found at www.eia.gov/outlooks/aeo/

- NREL's Regional Energy Deployment System (ReEDS) – ReEDS is an optimization model used to measure policy impacts on the electric power sector. The specific modeling that was evaluated in this discussion appears in *Evaluating Impacts of the Inflation Reduction Act and Bipartisan Infrastructure Law on the U.S. Power System* (March 2023). The two specific cases that were evaluated were: (i) IRA-BIL Mid Case; and, (ii) IRA-BIL Constrained Deployment.[3] ReEDS uses AEO 2022 Reference Case to forecast future electrical demand.[4]
- EPRI's U.S. Regional Economy, Greenhouse Gas, and Energy (REGEN) – REGEN is a capacity planning and dispatch model of the electric power sector. The specific modeling that was evaluated in this discussion appears in *Power Plant Performance Standards and Tax Credit Interactions: Impacts of Design Decisions and the Inflation Reduction Act on the U.S. Power Sector – An EPRI White Paper (*March 2023). The Reference Case was evaluated, which includes all On-the-Books federal and state policies and incentives, including IRA as of November 2022.[5]
- RFF Haiku – Haiku is a simulation model of regional electricity markets and interregional electricity trade in the continental United States. The model accounts for capacity planning, investment, and retirement over a multi-year horizon in a perfect foresight framework, and for system operation over seasons of the year and times of day. The specific modeling that was evaluated in this analysis appears in *A New Baseline for the Power Sector: Insights from the Haiku and E4ST Models* (February 15, 2023), which includes the IRA.[6]

3.2 Inclusion of IRA Provisions

Table 3-1 lists those IRA provisions that were accounted for in each model. The focus is on provisions that apply to the electric power sector.

[3] Mid Case – Moderate cost and performance for all technologies and delivered fuel prices are from the AEO2022 Reference Case. Constrained Deployment – Reduced land area/resources available for renewable development, new long-distance transmission build restricted to historical national average build rate (1.4 TW-mi per year), Increased (2x) cost of CO2 pipeline, injection, and storage infrastructure.

[4] Information on ReEDS can be found at www.nrel.gov/analysis/reeds/

[5] Information on REGEN can be found at www.epri.com/research/products/000000003002016601

[6] Information on Haiku can be found at www.rff.org/topics/data-and-decision-tools/haiku-electricity-model/

Table 3-1. Inflation Reduction Act Provisions in Each Model

Provision	IPM	AEO2023	ReEDS	REGEN
Production Tax Credit Extension	√	√	√	√
Investment Tax Credit Extension	√	√	√	√
New Clean Electricity Production Credit (45Y)	√	√	√	√
New Clean Electricity Investment Credit (48E)	√	√	√	√
Manufacturing Production Credit (45X)	√			
CCS Credit (45Q)	√	√	√	√
Nuclear Production Credit (45U)	√	√	√	√
Production of Clean Hydrogen (45V)	√			√
Solar in Low-Income Communities				√

As shown in Table 3.1, the number of provisions accounted for in each model varies. Of note, there was very little guidance from the Internal Revenue Service (IRS) when these models were run to evaluate the IRA. For example, ReEDS did not capture all the provisions that could directly or indirectly impact the electric power sector. Specifically, it did not capture the tax credit for clean energy production (45V) or the 45Q tax credit for direct air capture and storage of CO2.[7] Indeed, modeling any IRA impacts given the lack of guidance requires numerous subjective decisions. Consequently, the cost of monetizing tax credits under various IRA scenarios becomes important and can impact the effect of IRA on the electric power sector. For example, EPRI's REGEN model estimates an almost 37.5 percent reduction in Levelized Cost of Energy (LOE) for both On-Shore Wind and Utility-Scale Solar in 2030.[8] While ICF, which runs IPM for EPA, estimates IRA incentives could drive down solar by as much as 35 percent and wind by 49 percent by 2030.[9]

But more importantly, the IRA is still evolving through guidance making it somewhat difficult to model. An example of this evolvement can be seen through the three major clean energy tax provisions related to the production and investment tax credits, which have seen their guidance

[7] The IRS requested comments on these two provisions asking commenters to specify issues on which guidance is needed. The comment period closed December 3, 2022.
[8] Bistline et al, *Economic Implications of Climate Provisions of the Inflation Reduction Act*, Brookings Papers on Economic Activity, Spring 2023.
[9] ICF, *5 Actions for Utilities to Prepare for the IRA Impacts*, 2023

documents stretched over several months. The initial guidance of the Prevailing Wage & Apprenticeship provision (Notice IR-2022-61) was issued on November 30, 2022, while the initial guidance for the Domestic Content Bonus (Notice IR-2023-102), was issued on May 12, 2023, and the guidance for the Energy Community Bonus Credit (Notice IR-2023-29) was released on April 4, 2023. However, on June 15, 2023, the IRS released an update of the Energy Community Bonus Credit (Notice IR-2023-45) clarifying a special rule for beginning new construction.

Also, the IRS has asked for comments on several provisions, such as the Production of Clean Hydrogen (Notice IR-2022-58), which were due on December 3, 2022, but have yet to release any initial guidance. The IRS wanted commenters to specify issues for which guidance was needed.

3.3 Coverage of Environmental Regulations

Table 3-2 lists those environmental regulations that were accounted for in each model. REGEN did not list specific environmental regulations, but it does consider non-CO2 emission constraints.

Table 3-2 List of Environmental Regulations Included in Each Model

Regulation	IPM	AEO2023	ReEDS	REGEN
Proposed GNP	√			
CSAPR	√	√	√	
New, Modified GHG Standards: EGUs	√	√		
MATS	√	√	√	
Various Current and Existing State Regulations[10]	√	√	√	
Current and Existing RPS & Clean Energy Standards	√	√	√	√
Regional Haze and BART	√			
CA AB 32 and RGGI	√	√	√	√
Non-air Regulations: 316(b), ELG and CCR	√			

3.4 Modeled Coal Capacity

As shown in Table 3-3 below, all models forecast coal capacity in their Base/Reference Case to be in excess of 100 GW in 2030, except IPM which projects 69 GW in 2030.[11] IPM's 2030 coal capacity is almost 40 percent below, the average coal capacity projected by the other models.

[10] IPM's and ReEDs Current and Existing State Regulations are through 2020; whereas AEO2023 seem to be through 2021.

[11] It should be noted, that both REGEN and Haiku estimates are based upon an approximation of coal, renewable/storage, and natural gas capacity from figures in each report.

When EPA modeled the proposed Good Neighbor Policy (Transport Rule), IPM projected 2030 coal capacity to be 132 GW, which illustrates that the coal capacity forecasted under the proposed GNP will be higher than some projections without the proposed GNP, as shown in Table 3-3.[12] Therefore, the major diver in reducing coal capacity from 2028 to 2030 in the Updated Baseline is the modeler's assumptions about the IRA.

This proportional difference between AEO 2023 and IPM's Updated Baseline increases when one looks at years beyond 2030 due to the IRA. By 2045, IPM's coal capacity is projected to be 70 percent below AEO's. Under the proposed Integrated Proposal, IPM drastically reduces the amount of coal capacity further, to a point where only 500 MW of coal would be operating in 2045. Of note, all coal operating in 2035 and beyond under IPM's Integrated Proposal is equipped with CCS. In IPM's modeling platform, the CCS 45Q provision is available for 12 years, after which a coal unit with CCS no longer receives the tax credits and must be dispatched based upon unsubsidized operating costs.

Table 3-3. Comparison of Forecasted Coal Capacity Levels (GW)

Year	AEO2023	IPM Updated Baseline	EPRI ReGEN	NREL ReEDS - Mid/Const.	RFF Haiku	IPM-Integrated Proposal
2025	164	NA	≈165			
2028	127	100		143.9/154.4		99
2030	102	69	≈104	136.4/140.8	≈112.5	57
2035	92	44	≈99		≈100	13
2040	77.0	36				9
2045	74.1	22				0.5

How this coal capacity is operated varies significantly between the models, as shown in Appendix 3.0 - Operations. Specifically, AEO 2023 coal capacity factors (CF) are expected to remain consistent through the 2028 to 2045 time period (between 38% and 43%). ReEDS, which has the highest level of coal capacity operating in 2028 and 2030, has its coal capacity operating at CF in the high 20 percent ranges. IPM in its Base/Reference Case has coal CFs on a steady decline from 2028 to 2045 (55% to 12%); whereas, under the Integrated Proposal, the IPM CFs are somewhat erratic due to the shrinking level of coal capacity.

3.5 Modeled Renewable and Storage Capacity

As shown in Tab 3-4, the level of renewable capacity that IPM projects in its Base/Reference Case is significantly less that what is projected by the other models. Given the level of coal capacity IPM retires in its Base/Reference Case, one would expect a greater amount of renewable/storage capacity to be installed, especially in 2028 and 2030. Also of note, under IPM's Integrated Proposal, in which future coal capacity is brought to almost zero, the additional renewable/storage capacity only increases by a few gigawatts.

[12] US Environmental Protection Agency, *IPM SSR Report on the Proposed Rule,* March 11, 2022.

Table 3-4. Comparison of Forecasted Renewable/Storage Capacity Levels (GW)

Year	AEO2023	IPM Updated Baseline	NREL ReEDS - Mid/Const.	RFF Haiku	IPM-Integrated Proposal
2025		NA			NA
2028	618	298	676.4/610.1		295
2030	704	397	855.2/808.8	≈1012.5	398
2035	869	671		≈1125	665
2040	1000	871			878
2045	1134	1071			1076

So, what does all this mean? To truly measure the effect of renewable/storage capacity replacing retired coal capacity, one needs to evaluate the difference between future capacity levels with and without the IRA. Both AEO 2023, ReEDS and IPM have modeled a pre- and post-IRA reference cases, which are shown in Appendix 3.0 – Replacement Capacity.[13] The important metric is the amount of Renewable MW required to replace 1 MW of coal. These replacement ratios are highlighted in yellow for AEO, ReEDS and IPM.

As one can see from Table 3-5, AEO 2023 has more than 20 times more renewable/storage capacity replacing one MW of retired coal, while ReEDS have anywhere from 15 to 20 times more renewable/storage capacity replacing one MW of retired coal in comparison to IPM. Whereas, IPM has a very low replacement rate in both 2028 and 2030 and begins to increase slightly in 2035. But more importantly, under IPM's Integrated Proposal, in which coal capacity goes to zero, the replacement ratio is the same as the Base/Reference Case. One major factor that may contribute to these major discrepancies between these three models is how the capacity (accredited) credit is determined from intermittent resources. The capacity credit is an intermittent resource's contribution toward reserve margin requirements during peak load.

Table 3-5. Comparison of Level of Replacement Capacity (GW)

	AEO Renewable to Coal Replacement	ReEDS Renewable to Coal Replacement	IPM Updated Baseline Renewable to Coal Replacement	IPM Integrated Proposal Renewable to Coal Replacement
2028	41.4	14.9	1.5	1.4
2030	19.5	22.6	1.8	1.8
2035	24.2		5.3	5.3
2040	21.6		9.1	9.0
2045	23.9		9.6	9.6

[13] NEMS modeled a scenario in AEO 2023 without IRA along with its Reference Case, which included IRA and as mentioned earlier, IPM modeled a Pre- and Post-IRA 2022 Reference Case.

Why are these replacement ratios a concern? Because renewable generation is dependent on uncontrollable factors such as the amount of sunshine or wind, the installed capacity of a renewable resource reflects the amount of generation at peak energy-producing weather. To account for the variant nature of the weather, transmission organizations typically do not count on the installed capacity of a renewable resource when assessing reliability. Given the operating characteristics of these renewable resources, for example, PJM indicated one needs multiple megawatts to replace 1 MW of dispatchable, thermal generation.[14] Some examples of approximate nameplate capacity needed to replace 1 MW of thermal generation: (i) Solar – 5.2 MW; (ii) Onshore Wind – 14 MW; and, (iii) Offshore Wind – 3.9 MW. This seems to be the underlying premise behind AEO 2023 and ReEDS's higher levels of installed renewable/storage capacity: these models are acknowledging a concern regarding how renewable generation is able to meet its contribution to the reserve margin during peak load; thereby requiring a higher level of grid capacity from other resources (renewables, coal, gas) to avoid reliability issues. The premise is consistent with PJM's assessment of the need for additional megawatts from intermittent resources to fully replace retired coal capacity. It is only in 2035 that IPM begins to have multiple megawatts of renewable capacity replacing one megawatt of coal. Consequently, IPM's low replacement ratios in both 2028 and 2030, raise potential grid reliability issues during that time frame.

3.6 Modeled Natural Gas Capacity

Both AEO 2023 and IPM in the Base/Reference Case and IPM in the Integrated Proposal NGCC and NGCT capacity closely approximate each other, as shown in Appendix 3.0 – Model_Comparisons. Here, natural gas generation appears to be replaced by renewable generation.

ReEDS in its IRA scenarios is the only model that clearly discusses transmission infrastructure. Specifically, ReEDS contain several loan and grant programs to support new transmission infrastructure, which are not modeled but are assumed to facilitate modeled outcomes. Although these programs are not directly modeled, ReEDS increased transmission deployment across the IRA scenarios. Under the IRA Mid case, over 24 TW-miles of new long-distance transmission is deployed by 2030, a 16% increase in total installed capacity relative to today. This observed increase in transmission is largely driven by the increased deployment of wind (and solar) technologies in the IRA cases. The additional transmission enables access to more remote renewable resources and most likely explains ReEDS high levels of renewable/storage capacity in both 2028 and 2030.[15]

[14] PJM, *Energy Transition in PJM: Resource Retirements, Replacements & Risks*, February 24, 2023.

[15] Steinberg et al, *Evaluating Impacts of the Inflation Reduction Act and Bipartisan Infrastructure Law on the U.S. Power System* (March 2023).

3.7 Summary of Key Points

Some key points:

- EPA's modeling of the IRA, when compared to the other models is an unreasonable outlier. in particular regarding modeled coal and renewable/storage capacity in 2030.
- EPA adopted a very "optimistic" approach to the IRA, while lacking guidance from the Department of Treasury.
- EPA assumes IRA's financial provisions will alleviate uncertainties the industry will face during this transition period.[16] These assumptions dismiss concerns regarding supply chain problems, siting, labor shortages, infrastructure.
- EPA failed to understand that intermittent and limited duration resources require multiple megawatts to replace one megawatt of dispatchable generation, specifically in 2028 and 2030; thereby, failing to address grid reliability in 2028 and 2030.
- EPA seems to be dismissing the role of coal, assuming coal units will no longer serve as baseload capacity.

[16] EPRI-Resources of the Future, *Modeling the New Baseline for Electricity in the Presence of IRA*, February 15, 2023.

4 IPM's UPDATED BASELINE DOES NOT CONSIDER KEY CHALLENGES FACING THE POWER SECTOR'S TRANSITION FROM DISPATCHABLE FOSSIL GENERATION TO RENEWABLES

EPA's IPM 2030 Updated Baseline modeling fails to address and account for grid reliability issues confronting the electric power sector by replacing firm power with non-firm renewable generation without any consideration of the different nature of these two types of generating assets.

As discussed, in Section 3, EPA's IPM 2030 Updated Baseline failed to model enough new capacity to replace the level of coal-fired capacity retired in 2030. Consequently, the 2030 Electric Power Profile is flawed and does not reflect the energy mix needed in 2030 to maintain reliability. EPA should consider those major transition and reliability issues that electric generators and RTOs are confronting now and for the next seven years when modeling electric generation in 2030. Specifically, to ensure that the modeling results reflect grid reliability considerations, EPA must consider in its modeling, among others, factors relating to capacity in queues, length of time in the queues, project completion of renewables and accredited capacity of renewable sources.

EPA's current modeling relies on a very optimistic interpretation of the IRA, even though there has been a lack of guidance from the Department of Treasury, when EPA undertook this modeling. Modeling the IRA impacts requires numerous subjective decisions given this lack of guidance. EPA's approach has been, contrary to every other agency and entity that has considered the issue, to make wildly optimistic assumptions and to assess the likely impact of proposed regulatory programs with major impacts on the reliability of the electric grid (and, indeed, the entire American economy) base on these assumptions. In short, EPA simply assumes IRA's financial provisions will alleviate all the uncertainties the industry will face during the ongoing transition towards increasing renewable generation.[17] These assumptions dismiss concerns regarding supply chain problems, siting, labor shortages, infrastructure, permitting and transmission.

Why is it important that EPA in its modeling focus on these reliability issues? In testimony before the US Senate Committee on Energy & Natural Resources, Manu Asthana, President of PJM Interconnection highlighted concerns related to the mismatch between current resource retirements and low entry of replacement capacity as follows: [18]

[17] EPRI-Resources of the Future*, Modeling the New Baseline for Electricity in the Presence of IRA*, February 15, 2023.

[18] Testimony of Manu Asthana, United States Senate Committee on Energy & Natural Resources, June 1, 2023.

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- The rate of electricity demand is likely to continue to increase from electrification and increasing deployment of high-demand data centers in the region.
- Dispatchable generators are retiring at a rapid pace largely due to government and private sector policies.
- Replacement generation is primarily intermittent and limited-duration resources, requiring multiple megawatts of these resources to replace one megawatt of dispatchable generation.
- 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.

These concerns were further reiterated by James Robb, President and CEO of the North American Electric Reliability Corporation (NERC) at the same Senate hearing, when he stated that the rapid, often disorderly transformation of the generation resource base and performance issues associated with replacement resources as conventional units retire are contributing to the deterioration of the grid.[19] What follows is a discussion of those reliability issues that EPA needs to consider in its modeling

4.1 What is the Interconnection Queue?

The queue for electric generating resources represents the time a project developer initiates an interconnection request and thereby enters the queue, which is followed by a series of interconnection studies. The studies culminate in an interconnection agreement, which is a contract between the RTO or utility. After this interconnection agreement, the project still must be built; however, most proposed projects are withdrawn during the interconnection study process.

Below is a table of capacity in the queue for four RTOs taken from several sources. The PJM interconnection capacity is as of April 1, 2023, while the Electric Reliability Council of Texas (ERCOT) and Southwest Power Pool (SPP) interconnection capacity is of June 28, 2023 and was prepared by S&P Global.[20/21] The Midcontinent Independent System Operator (MISO) capacity data were reported on June 19, 2023 by S&P Global Market Intelligence.[22]

[19] Testimony of James B, Robb, United States Senate Committee on Energy & Natural Resources, June 1, 2023.
[20] Testimony of Manu Asthana, United States Senate Committee on Energy & Natural Resources, June 1, 2023.
[21] S&P Global, *2023 U.S. interconnection queues analysis*, June 2023.
[22] S&P Global Market Intelligence*, Grid expansion again in focus as MISO grapples with decarbonization*, June 19, 2023.

Table 4-1. Interconnection Queue Capacity

Region	Interconnection Queue Capacity (GW)	Share of Renewable Capacity (%)
PJM	253	97.2
ERCOT	245	95.1
MISO	281	97.0
SPP	131	95.4

As one can see, these queues are mainly composed of intermittent resources, so the major question is how much of this capacity will eventually get built.

4.2 Small Number of Projects are Actually Built

As shown above, PJM's queue mainly consists of renewable sources; however, these renewable projects have a historical completion rate of 5 percent (queue to steel in the ground).[23] Last year, only 2 GW of capacity was built in PJM, of which only 700 MW (2.3% of the total capacity with signed interconnection agreements) were renewable capacity. This is compared to over 30 GW of generation with signed interconnection agreements.[24]

PJM on July 10th officially launched the transition to "first ready, first served" approach to expedite projects through the queue. This approach includes decision points along the way at which time developers must submit readiness deposits and demonstrate site control or withdraw their projects.[25]

Project completion rates are not only an issue within PJM but nationally. Only 14 percent of solar and 20 percent of wind projects requesting interconnection from filing dates from 2000-2017 reached commercial operation by the end of 2022. In addition, the average time projects are retained in queues has increased markedly. The typical project built in 2022 took 5 years from the interconnection request to commercial operation, compared to 3 years in 2015 and less than 2 years in 2008.[26]

[23] PJM, *Energy Transition in PJM: Resource Retirements, Replacements & Risks*, February, 24 2023.
[24] Testimony of Manu Asthana, United States Senate Committee on Energy & Natural Resources, June 1, 2023
[25] PJM Inside Lines, *Transition to New Interconnection Process Begins July 10*, July 6, 2023
[26] Rand et al, *Queued U: Characteristics of Power Plants Seeking Transmission Interconnection as of the End of 2022*, Lawrence Berkeley National Laboratory, April 2023.

A major factor that is impacting these completion rates is the various interconnection costs associated with renewable generation. These costs have exploded over the past years suggesting limited transmission availability. For example, in ISO New England (ISONE), interconnection costs are the highest for onshore wind ($909/kW) followed by solar ($400/kW) and storage ($230/kW).[27] Nearly all (81%) of onshore wind projects since 2018 have withdrawn their applications, suggesting that high interconnection costs are a driver of these withdrawal decisions. On the other hand, natural gas interconnection costs are $91/kW. The Berkeley study concluded that many projects facing high interconnection costs withdraw from the queue and renewable and storage projects have higher interconnection costs than natural gas.[28]

Of note, there is no discussion in the EPA's *Documentation for EPA's Power Sector Modeling Platform v6 Using the Integrated Planning Model – Post-IRA 2022 Reference Case* (March 2023) of interconnection queues or project interconnection rates.

4.3 The Importance of Accredited Capacity

An important consideration, about new renewable capacity is the ratio of installed capacity to the level of accredited capacity that can be considered to replace retired thermal generation. Accredited capacity reflects how much generation capacity a unit is expected to meet during constrained conditions (accounting for historic performance), which is much less than the installed capacity of the unit for non-dispatchable renewable generation. RTOs have generally applied the following percentages to installed capacity to determine accredited capacity for renewables:

- Wind 15-20%
- Solar (Summer) 45-60%
- Solar (Winter) 3-12%
- Storage 65-90%

These ranges reflect the location and the class of renewable generation source. Of note, in examining EPA's *Documentation for EPA's Power Sector Modeling Platform v6 Using the Integrated Planning Model – Post-IRA 2022 Reference Case*, it is unclear how IPM handled accredited capacity for renewable resources, and EPA does not spell out how accredited capacity is handled for various renewable resources.

As discussed earlier, present-day queues are mainly composed of intermittent and limited duration resources. Given the operating characteristics of these resources, PJM indicated the grid would need multiple megawatts to replace 1 MW of thermal generation.[29]

[27] Seel et al, *Generator Interconnector Costs to the Transmission,* Lawrence Berkeley National Laboratory, June 2023.
[28] Id.
[29] PJM, *Energy Transition in PJM: Resource Retirements, Replacements & Risks*, February 24, 2023.

For example, MISO expects to retire 26.1 GW of coal capacity over the next seven years (between 2023 and 2030). However, as shown in the table below, MISO's new resources, primarily wind and solar, have a much lower accredited generating capacities than the fossil resources they are replacing.[30] Table 4-2 illustrates the difference between MISO summer installed and accredited capacity for wind and solar today and in 2031

Table 4-2. Comparison of MISO Summer Capacity

	Today		2031	
Category	Installed Capacity	Accredited Capacity	Installed Capacity	Accredited Capacity
Wind	25.6	4.6	56.0	10.1
Solar	4.7	2.1	56.3	12.9

Table 4-2 indicates forward years will encounter a higher degree of uncertainty regarding the accredited capacity available to replace the 26.1 GW of coal capacity by 2031; thereby, putting the region at risk of a capacity shortfall.

Just recently, MISO indicated a possible 2.1 GW accredited capacity shortfall in the summer of 2025 and growing to 9.5 GW in the summer of 2028.[31] These deficits are primarily attributed to MISO's planned accreditation reforms, which could see wind drop from 40% to 14% accredited value in the winter, meaning on paper these megawatts never existed and begin to reveal a major impact on reliability.

4.4 Steps RTOs are Taking to Ensure Reliability

To ensure current grid reliability during this period of energy transition two RTOs and individual generators have taken the following actions:

Southwest Power Pool (SPP). In addition to growing interconnection queues at SPP, the RTO is developing a plan to pay generators to delay retirements to help maintain reliability.[32/33]

Midcontinent ISO (MISO). Delayed retirements of generation units helped reverse a current capacity shortfall in MISO. Units that delayed retirements for reliability reasons are:[34]

[30] MISO, *2022 Regional Resource Assessment, A Reliability Imperative Report*, November 2022.
[31] S&P Global Market Intelligence, *Midcontinent ISO, states eye possible 2.1 GW capacity shortfall in 2025,* July 17, 2023.
[32] S&P Global Market Intelligence, *Study finds "dramatically' growing interconnection queues, cost in SPP region,* May 17, 2023.
[33] S&P Global Market Intelligence*, SPP details plan to generators to delay retirements, help with reliability*, May 25, 2023.
[34] S&P Global Market Intelligence, *Delayed generator closures helped reverse capacity shortfall in MISO*, May 22, 2023.

- Rush Island (1.2 GW) – 2022 to 2025
- RM Schahfer 17 & 18 (722 MW) - 2023 to 2025
- Edgewater 5 (380 MW) – 2022 to 2025
- Columbia 1 & 2(1.1 GW) – 2024 to 2026
- South Oak Creek (1.1 GW) – 2023/24 to 2024/25

This delayed retirement of a total of 4.5 GW of capacity helped avert a capacity shortfall and ensure a sufficient supply in MISO's recent capacity auction for planning year 2023-24[35]. Of note, there are 24 coal units representing 10 GW of capacity that either delayed retirement or made a total conversion to natural gas due to reliability or supply chain issues.[36] Many of these delays extend into the 2025-2026 time period; however, 4.3 GW or 43 percent of this total are expected to extend to 2030 and beyond. Given the uncertainty around the transition to new generating resources, one can anticipate more retirement delays in the future.

4.5 Summary of Key Points

Unlike AEO 2023, which considered the impact of intermittent resources on the electric power industry, EPA's 2030 Updated Baseline failed to consider issues confronting RTOs and electric utilities about reliability and transition to non-dispatchable capacity. EPA continues to dismiss considerations of grid reliability by accelerating coal plant closures based upon wildly optimistic and wholly unrealistic assumptions about the impact of the IRA on the electric utility sector. EPA's IPM instantaneously "builds" new resources, without considering the many issues discussed above that are facing grid generators and operators. IPM is designed to ensure resource adequacy, which means it adds new resources, without the consideration whether these resources can or will be built. However, IPM is not capable of determining grid reliability because it does not consider the availability of essential reliability services (e.g., availability in all seasons, dispatchability), or other constraints (e.g., transmission) as spelled out by PJM and MISO.[37]
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[35] MISO, *Planning Resource Auction, Results for Planning Year 2023-24*, May 19, 2023.
[36] James Marchetti Inc, *EEMS Data Base.*
[37] PJM, *Evolving Resource Mix and System Reliability*, 2017 and MISO, *Identification of Sufficient System Reliability Attributes,* May 24, 2023.

5 IPM's MODELED UPDATED BASELINE IS FLAWED

The focus of this section is on the IPM 2030 Updated Baseline, because if there are significant flaws in the Baseline, the Integrated Proposal compliance results become unrealistic. The Updated Baseline is the Post-IRA 2022 Reference Case (March 2023), where IPM predicts a significant drop in operating coal capacity in 2030, in comparison to the 2030 operating coal capacity that is modeled for the Effluent Limitation Guidelines (ELG) Pre-IRA 2022 Reference Case (January 2023). Specifically, the Pre-IRA 2022 Reference Case predicts 111.8 GW of operating coal capacity in 2030, while the Post-IRA 2022 Reference Case predicts 68.9 GW of operating coal capacity in 2030, with major shifts to intermittent/non-dispatchable generating sources.

The primary factor contributing to the decline in baseline operating coal capacity, according to EPA, is the inclusion of the IRA in the Post-IRA 2022 Reference Case. The handling of the IRA within IPM causes a significant reduction in baseline coal capacity which distorts actual retirements and reliability, as well as compliance costs attributed to the Integrated Proposal.

The Post-IRA 2022 Reference Case platform uses demand projections from the Energy Administration's Annual Energy Outlook (AEO) 2021. The IPM Post-IRA Reference Case reflects the latest data and regulations affecting the power sector, and they include:

- New Cost and Performance Assumptions for Fossil and Renewable Technologies
- Tax Credit Extensions from the IRA for wind, solar, hydro, geothermal, landfill gas, energy storage, biomass and 45Q
- Minimum Capacity Factor requirements of 10 percent applied to existing coal units in regions without capacity markets
- Updates of Nuclear Unit Operational Assumptions to reflect pre-specified life and are no longer endogenously retired
- CCS Costs and Performance Updated and the 45Q modeled in 2030 and 2035
- Greater Detail on Operating Reserves

The Post-IRA 2022 Reference Case considers compliance with various regulations, which are summarized below:

- Inflation Reduction Act of 2022 (IRA)
- Proposed Good Neighbor Plan (Transport Rule)
- Revised Cross-State Air Pollution Rule (CSAPR) Update Rule
- Standards of Performance for Greenhous Gas Emissions from New, Modified and Reconstructed Stationary Sources: Electric Utility Generating Units
- Mercury and Air Toxics Standards Rule, which was finalized in 2011

- Various current and existing state regulations
- Current and existing renewable portfolio standards (RPS) and current energy standards
- Regional Haze Regulations and Guidelines for Best Available Retrofit Technology (BART)
- Platform reflects California AB 32 and RGGI
- Three non-air federal rules affecting EGUs: (i) Cooling Water Intakes (316(b) Rule; (ii) Coal Combustion Residuals (CCR), which reflects EPA's July 29, 2020 position on retrofitting or closure of surface impoundments; and, (iii) Effluent Limitation Guidelines, which includes the 2020 Steam Electric Reconsideration Rule (cost adders were applied starting in 2025).

5.1 Analytical Approach

The focus is to identify those units IPM modeled as coal retirements, CCS retrofits and coal to gas conversions (C2G) in both 2028 and 2030 and compare them to announced plans for unit retirements, technology retrofits and C2G conversions, in addition to identifying any modeling inconsistencies.

EPA did not provide any parsed file for either the 2030 Updated Baseline or Integrated Proposal, so we had to create our own parsed files for the Updated Baseline and Integrated Proposal using four different IPM files: (i) 2028 parsed file of the Post-IRA 2022 Reference Case; (ii) Updated Baseline and Integrated Proposal RPE File for the year 2030; (iii) Updated Baseline and Integrated Proposal RPT Capacity Retrofits File for the year 2028 and 2030; and, (iv) NEEDS Data File for the Post-IRA 2022 Reference Case.[38] The development of these two parsed files allows for the identification of IPM modeled retirements in 2028 and 2030, CCS retrofits in in 2030 and C2G in both 2028 and 2030. These modeled retirements and conversions were compared to announced information in the James Marchetti Inc EEMS Data Base.

This analytical approach yielded 68.1 GW of operable coal capacity (coal, pet coke and waste coal) in the 2030 Updated Baseline, which is roughly the same as, but slightly below IPM's 2030 modeled value of 68.9 GW.[39] In terms of the 2030 Integrated Proposal, this analytical approach yielded 57.9 GW of operable coal capacity, which is slightly higher than IPM's modeled value of 57.3 GW. The closeness of these values indicates the coal inventory we are working with matches the IPM inventory.

[38] This is tedious work that would have been unnecessary had EPA provided the parsed files, as it has done in the past. It took a long time and prevented us from further analyzing the IPM results that EPA added to the docket after July 7, 2023, and refused to extend the comment period to allow for a more thorough analysis.

[39] U.S. EPA, *Integrated Proposal Modeling and Updated Baseline Analysis, Memo to the Docket* (EPA_HQ_OAR_2023_0072), July 7, 2023.

In addition, to determining the total operable coal capacity in 2030, our approach was able to determine the following; (i) the amount of coal capacity IPM retired in 2028 and 2030; (ii) amount of capacity converted to natural gas (C2G) in 2028 and 2030; and, (iii) amount of coal capacity retrofitted with CCS in 2030.

5.2 Coal Retirements

In the 2028 Updated Baseline model run, IPM had 108 coal units retired (51.4 GW) from 2023 to 2028. In the 2030 model run, IPM retired an additional 58 coal units (28.5 GW). The total number of retirements for the two Updated Baseline modeling runs is 166 coal units (79.9 GW), see Appendix 5.0 – 2028_2030 Coal Retirements.

Table 5-1 summarizes the IPM retirement errors identified in the 2028 and 2030 modeling runs. Specifically, IPM incorrectly retired 41 coal units (18.1 GW) by 2028 and additional 25 coal units (15.9 GW) in 2030 in the Updated Baseline. As shown in Appendix 5.0 – 2028_2030 Coal Retirements, these 66 retirement errors (34.0 GW), which account for almost 40 percent of the modeled retirements in the Updated Baseline are based upon current public information that indicates these units will remain in operation. The Notes section of this appendix presents those sources used to identify these errors. This is an extremely high percentage of erroneous coal retirements, resulting from EPA's unrealistic assumptions of IRA implementation, leading to a significantly comprised Updated Baseline. These errors center around coal units continuing to operate beyond 2028 or 2030 or coal units switching to gas.

Table 5-1. IPM Modeled Coal Retirement Errors

Year	IPM Unit Retirements	Unit Retirement Errors
2028	108	41
2030	58	25
Total	166	66

In addition, there are three coal units (1.6 GW) that EPA listed in its NEEDS file as being retired before 2028 that are expected to operate beyond 2030.

In terms of the Integrated Proposal, IPM retired an additional 17 coal units, resulting in 183 coal units (83.2 GW) being retired through 2030.

5.3 Coal-to-Gas Conversions

The number of units IPM converted in both the Updated Baseline and Integrated Proposal in the 2028 modeling run are the same, as shown in Appendix 5.0 – 2028_2030_C2G. IPM converted 35 coal units (13.7 GW); however, there are 7 coal units (3.0 GW) that have either been mischaracterized or will be retired.

Moving to 2030, IPM converted only two units to gas (Turk and Sandy Creek) in the Updated Baseline. Both seem highly unlikely, since these units are two of the newest coal units operating. In the Integrated Proposal, IPM converted 11 units (7.5 GW), but much like the units in the Updated Baseline, except for Elm Road and Weston 4, the remaining 8 conversions are highly unlikely by 2030 due to either retirements or lack of public announcements on a coal to gas conversion.

5.4 Coal CCS

IPM projected that by 2030, 30 units would retrofit CCS in the Updated Baseline and 39 units in the Integrated Proposal, as shown in Appendix 5.0 – CCS. However, none of these units have been involved in any Front-End Engineering and Design (FEED) Studies. Moreover, of all the units listed 15 will either be retired or converted to natural gas in and around 2030 as provided by the Notes in Appendix 5.0 – CCS. There are major questions addressing infrastructure and project implementation that present challenges to IPM's CCS projections in 2030. Indeed, it is next to impossible for these units to be able to retrofit CSS by 2030, regardless of any optimistic assumptions regarding IRA incentives.

An elaboration of the shortcomings of CCS and rationale as to why such technology cannot be applied to 39 units in 10 years is presented in a technical background document[40] accompanying the comments of APPA and NRECA. The key shortcomings in EPA's projection of CCS applicability are summarized as follows:

- CCS remains an evolving technology, without the basic understanding and experience of a "mature" process. Additional lessons learned have yet to be acquired that are necessary to refine design.

- EPA's prime contractor to develop the implementation schedule – Sargent & Lundy – although projecting a schedule of 7.25 years, clearly state in their deliverable document that the schedule accounts only for "on-site" activities, and not those external to the site but critical for execution.[41] S&L also specify potential "roadblocks and "bottlenecks" that will impose delays.

- The cumulative experience of seven CCS projects that are currently in planning, or the subject of FEED design suggests most will require more than 10 years from "concept" to CO2 injection – with the most uncertainty assigned to permit acquisition for sequestration site or pipelines to transport CO2 for enhanced oil recovery or sequestration.

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[40] Cichanowicz et al, *Technical Comments on the Carbon Capture Utilization and Sequestration aspects of the Proposed New Source Performance Standards for GHG Emissions from New and Reconstructed EGUs; Emission Guidelines for GHG Emissions from Existing EGUs; and Repeal of the Affordable Clean Energy Rule,* August 7, 2023.

[41] S&L_CCS_Schedule_EPA-HQ-OAR-2023-0072-0061_attachment_16.pdf.

5.5 Coal Delayed Early Retirements

IPM modeled a delayed coal retirement option for 85 facilities representing 45 GW in the 2030 Integrated Proposal. This means these 85 facilities would fall into the Near-Term subcategory for existing coal under the proposed Clean Air Act Section 111d rules, which means they would cease operation after December 31, 2031 and before January 1, 2035 and commit to an annual capacity factor of 20 percent. This means these units must retire by January 1, 2035. However, for 35 of these facilities IPM had modeled their retirement in the 2030 run year, which encompasses the years 2029 to 2031. Plus, IPM installed CCS in 2030 for four of these units. So, the question is why are these previously modeled 2030 retired units and CCS installations included in this subcategory? Their inclusion represents a significant modeling disconnect, bringing into question the entire modeling of this option.

5.6 Other Modeling Issues

Listed below are some other modeling issues that were identified:

- Fayette 3 and San Miguel had CCS installed in the 2030 Updated Baseline, but both units were retired in the 2028 Integrated Proposal
- Leland Olds 2 had a CCS installed in the 2030 Updated Baseline, but was retired in 2030 in the Integrated Proposal
- Coyote was retired in the 2030 Updated Baseline, but was "unretired" in the 2030 Integrated Proposal
- Craig 3 will have retired on December 31, 2029 but in the 2030 Updated Baseline installs a CCS
- Several units could not be found in the 2030 IPM modeling platform – Merom 1&2, Dave Johnston 1 and Morgantown Energy Facility

The retirement of CCS units in the Integrated Proposal defies logic and is a modeling disconnect. One installs a technology to reduce CO2 and take advantage of the 45Q tax credit in the Updated Baseline and is retired in the Integrated Proposal, which is designed to reduce CO2.

5.7 Summary of Key Points

The major issues associated with EPA's IPM modeling of the 2030 Updated Baseline and Integrated Proposal are summarized as follows:

- The Updated Baseline used to measure the compliance impacts of the proposed rules is seriously flawed, mainly attributed to EPA's assumptions on IRA implementation.
- Most notably, IPM erred in retiring 66 coal units representing 40 percent of the retired Updated Baseline coal capacity in 2030, which seriously compromises the baseline.
- IPM assumes retrofitted units with CCS in 2030, which is next to impossible for these units to retrofit CCS by 2030.

- There seems to be some significant modeling disconnects that will further comprise both the Updated Baseline and Integrated Proposal in 2030
- The IPM modeled compliance impacts for the proposed rule in 2030 is very likely misstated.