TN Department of Environment & Conservation

TESTIMONY OF MICHELLE WALKER OWENBY
DIRECTOR OF THE DIVISION OF AIR POLLUTION CONTROL FOR
THE TENNESSEE DEPARTMENT OF ENVIRONMENT AND CONSERVATION
BEFORE HOUSE SUBCOMMITTEE ON ENVIRONMENT, MANUFACTURING, AND CRITICAL MATERIALS

Hearing: Clean Power Plan 2.0: EPA's Effort to Jeopardize Reliable and Affordable Energy for States
November 14, 2023

- EPA's proposal to regulate Greenhouse Gas (GHG) Emissions from Fossil Fuel-Fired Electric Generating Units through New Source Performance Standards (NSPS) and Emission Guidelines proposes a Best System of Emission Reduction (BSER) that is not adequately demonstrated and fails to comply with Clean Air Act section 111.
- EPA's BSER for intermediate and baseload natural gas-fired combustion turbines requiring co-firing with low-GHG hydrogen is not adequately demonstrated as there is no production of low-GHG hydrogen in the U.S. and there is no known capability to produce, or planned infrastructure to transport, the low-GHG hydrogen that EPA prescribes. EPA's analysis uses projections for clean hydrogen, not low-GHG hydrogen. EPA's projections of low-GHG hydrogen requirements are understated and ignore growing load use occurring in the U.S. in places like Tennessee.
- EPA's BSER for carbon capture and storage (optional for large new and existing natural gas combustion turbines and required for modified or existing coal-fired boilers) requires carbon capture of 90% by specific dates but is not adequately demonstrated. None of the projects relied upon by EPA ever achieved 90% capture and most of the projects had demonstrable reliability issues.
- Critically, the CO_2 storage component of EPA's BSER has not been adequately demonstrated because storage site viability appears to be constrained by geography; development of CO_2 pipeline infrastructure is unregulated at the federal level; and distinct State requirements, property rights and safety concerns are likely to slow development of the necessary storage and transport network.

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Good morning Chairman Bill Johnson, Ranking Member Tonko and members of the Committee. I am Michelle Walker Owenby, Director of the Division of Air Pollution Control for the Tennessee Department of Environment and Conservation (TDEC). Thank you for the opportunity to appear before you to discuss the U.S. Environmental Protection Agency's (EPA) most recent rule proposal regarding regulating Greenhouse Gas (GHG) Emissions from Fossil Fuel-Fired Electric Generating Units through New Source Performance Standards (NSPS) and Emission Guidelines (Docket ID # EPA-HQ-OAR-2023-0072). This testimony represents a summary of Tennessee's comments regarding the rule proposal. The full set of comments can be found in EPA's rulemaking Docket.

State air directors across the United States are responsible for developing state plans for a number of the actions proposed in EPA's rule. As implementers of the Clean Air Act, state and local air programs take their role seriously; therefore, spend considerable time evaluating EPA's proposals to better understand what implementation may require and, if time allows, to address any concerns identified through written comments and often direct conversations with EPA staff across various levels. Because state and local programs are closest to the sources proposed to be regulated under this rule and have significant experience developing State Implementation Plans under the Clean Air Act, I am especially grateful for the opportunity to share our thoughts and concerns relative to this proposal.

EPA's Proposal

Section 111 of the Clean Air Act requires the EPA Administrator to establish and periodically revise a list of stationary source categories which, in the judgement of the Administrator, may reasonably be anticipated to endanger public health or welfare. Section 111(b) requires the Administrator to establish federal standards of performance for new sources within each source category, and Section 111(d) requires EPA to provide for the implementation and enforcement of standards of performance for existing sources (emission guidelines) within a source category.

On May 23, 2023, EPA proposed a number of actions under Section 111, including NSPS for GHG emissions from fossil fuel-fired stationary combustion turbines; NSPS for GHG emissions from modified coal-fired boilers; emission guidelines for GHG emissions from existing coal-fired boilers; and emission guidelines for GHG emissions from large stationary combustion turbines. EPA's proposed standards would require these units: (i) to adopt or convert their fuel sources to 96% low-GHG hydrogen (hydrogen produced through a process that results in a GHG emission rate of less than 0.45 kilograms of CO_2 equivalent per kilogram of hydrogen on a well-to-gate basis), and (ii) to implement carbon capture and storage (CCS) with a 90% capture efficiency. The effective date of these requirements depends on the specific source category but would become effective between 2032 and 2035 or 2038.

The "Best System of Emission Reduction"

Section 111 of the Clean Air Act creates standards of performance for new sources and emission guidelines for existing sources which must reflect "the degree of emission limitation achievable through the application of the best system of emission reduction [known as BSER] which (taking into account the cost of achieving such reduction and any nonair quality health and environmental impact and energy requirements) the Administrator determines has been adequately demonstrated."

The language of the Clean Air Act is of crucial importance here, because the Act explicitly states that BSER must be based upon technology that exists not in theory, but in fact. While reasonable extrapolation of existing technology may be acceptable, EPA may not simply disregard the lack of current availability. Indeed, courts have cautioned that EPA cannot base its determination upon mere speculation or conjecture. This fact underlies Tennessee's comments on the proposed standards – EPA speculates about technologies that do not currently exist or cannot reasonably be expected to exist in a commercially feasible manner on the scale and timeline set forth in the proposed rule.

EPA's Proposed Option for Low-GHG Hydrogen

EPA's proposed BSER around the use of low-GHG hydrogen has not been adequately demonstrated nor does it represent a reasonable extrapolation of what would be needed and what could happen when necessary for compliance with the proposal. For intermediate load and baseload natural gas-fired combustion turbines, EPA proposes BSER that requires facilities to burn at least 30% low-GHG hydrogen by volume beginning in 2032. For baseload turbines, EPA also proposes BSER to include either carbon capture and storage (CCS) by 2035 or combustion of 96% low-GHG hydrogen by volume beginning in 2038. Furthermore, EPA proposes that hydrogen qualifies as low-GHG hydrogen if it is produced through a process that results in a GHG emission rate of less than 0.45 kilograms of CO_2 equivalent per kilogram of hydrogen on a well-to-gate basis, consistent with the system boundary established in Internal Revenue Code section 45V (Credit for Production of Clean Hydrogen) of the Inflation Reduction Act (IRA). EPA bases its BSER demonstration upon: (1) the availability of turbines that combust or co-fire hydrogen; and (2) the projected availability of low-GHG hydrogen as a clean fuel.

The critical issue with EPA's BSER is that it relies on the projected availability of low-GHG hydrogen. The simple fact is that there is currently no production of low-GHG hydrogen in the United States, nor is there existing manufacturing capabilities or infrastructure in place to produce low-GHG hydrogen. Imposing a new standard with unproven technology and availability presents a slew of risks for both regulator and regulated entity, and EPA has not demonstrated that low-GHG hydrogen as a viable option for the electric generating sector.

EPA relies on projections for the production of a type of hydrogen that is not equivalent to the standard for low-GHG hydrogen it is requiring in the rule proposal. Specifically, EPA utilizes a Department of Energy estimate to predict that 10 million metric tons of "clean hydrogen production" will be available by 2030 and that 20 million metric tons will be available by 2040. However, EPA concedes that these estimates are not based on production of low-GHG hydrogen (less than 0.45 kilograms of CO_2 equivalent per kilogram of hydrogen) but of "clean" hydrogen produced in accordance with DOE's specification (less than 4 kilograms of CO_2 equivalent per kilogram of hydrogen). This is important, because at no point does EPA project how much hydrogen that meets its own standard will be available in the future.

Aside from concerns with EPA's projections, the proposed BSER is still problematic because EPA's estimate of the power sector's hydrogen needs appears to be significantly understated. EPA projected hydrogen use based upon its own modeling of what the power sector would look like in 2030 and 2040 and came up with an estimate that the need would be 2.2 million metric tons in 2030 and 2.8 million metric tons in 2040. However, EPA appears not to have considered the power sector *as it currently exists* (i. e., the number of coal plants, gas plants, nuclear plants, and renewable energy plants currently in operation). When future hydrogen needs are estimated from the source population as it currently exists, Tennessee estimates that future hydrogen needs could be over three times as much as DOE's mass-based estimate (67 million metric tons required compared to a projection of 20 million metric tons)[1]. While it is reasonable to assume coal units will continue to be retired as many utilities, including the Tennessee Valley Authority (TVA) that services most of Tennessee, have announced intentions to do so and it may be possible some gas turbines will be retired at some point, it is also important to understand that utilities in many areas of the country,

[1] The nation's hydrogen needs can be calculated on a mass basis (tons of hydrogen), volume basis (cubic meters of hydrogen), and a heat input basis (fuel value of hydrogen in British thermal units [Btu]). For the purposes of this testimony, Tennessee used a mass basis.

including Tennessee, are facing projections of load demand growth, not flat demand and certainly not decline. While we understand utilities are looking to diversify their generation make-up with non-fossil generation sources, doing so on what would become the mandated time constraints under this rule at the same time electricity demand is rising because of the return to and growth in U.S. manufacturing, electrification of the transportation sector, and, in some areas, population growth appears to be particularly aggressive and risky. These factors make EPA's projections on what the realistic need for hydrogen will be when the rule requires it absolutely critical.

BSER must be based on technology that has been adequately demonstrated or, following the rationale set forth by the courts, upon a reasonably-supported extrapolation of existing technology. However, EPA's proposed low GHG hydrogen is a fuel supply that does not currently exist. Indeed, the supply projections EPA relied on in the proposed rule are based on what would be considered conforming hydrogen under its own low-GHG hydrogen requirements. Further, EPA's projection of how much low GHG hydrogen is likely to be needed is understated. Finally, delivery of hydrogen from point of production to facilities will require a significant infrastructure investment regardless of whether it's delivered via pipeline or tanker trucks.

EPA's Carbon Capture Option

For new combustion turbines (CT), existing combustion turbines larger than 300 MW and operating at a capacity factor greater than 50%, and modified or existing coal-fired boilers, EPA proposes to require carbon capture and storage (CCS) as a component of BSER (gas-fired CTs can choose between CCS and combustion of low-GHG hydrogen, but CCS is the only compliance option for coal boilers). EPA proposes to require 90% capture of CO_2 beginning in 2035 for gas-fired combustion turbines and in 2040 for coal-fired units.

EPA offers several examples of working carbon capture systems to support its determination, and Tennessee acknowledges that EPA is on firmer ground here compared to its low hydrogen standard. However, none of the examples offered by EPA would satisfy the carbon capture requirements proposed in this rulemaking due to poor reliability and low nominal control efficiency, as follows:

- Only a single CCS system is currently in use at a coal-fired utility – SaskPower's Boundary Dam Unit 3 operation in Canada. EPA asserts that this system alone would be sufficient to demonstrate the CO_2 capture component of CCS. However, Unit 3 does not have a history of reliable operation and compliance with the proposed standard. Boundary Dam's system, at its best, appears to have never exceeded 65% CO_2 capture based on SaskPower's publicly available data[2], and the facility was frequently plagued with system outages and periods of poor control efficiency (between 0% and 25%). For the eight quarters of data that Tennessee reviewed, Boundary Dam Unit 3 was unable to meet EPA's proposed 90% capture efficiency ***even once***. Therefore, although CO_2 capture has been demonstrated, Boundary Dam Unit 3 does not support EPA's proposed numeric limits. Indeed, Boundary Dam Unit 3 suggests that EPA's proposed control efficiency is unachievable over the long term with current technology.
- EPA cites the Petra Nova carbon capture project in Texas as a second example of a working carbon capture system, and while this facility operated more consistently than Boundary Dam (i. e., with less downtime), this system was designed to capture only 33% of the unit's CO_2 emissions, and its actual capture efficiency ranged from 20-30%. Petra Nova, like Boundary Dam Unit 3, does not support EPA's BSER determination, because the facility's operating data suggest that this system is unable to comply with EPA's proposed limits.
- A third example cited by EPA is Shell Canada's Quest Carbon Capture and Storage project. This operation is a steam reforming plant that produces hydrogen from natural gas, and which, we believe, generates

[2] Since this is a Canadian Plant, there is no Acid Rain data for the unit, and Tennessee's comments were based on numeric data and graphical information obtained from SaskPower's website.

a stream of nearly pure CO_2. The Quest CCS project operates on a smaller scale and under near-ideal conditions[3], but this plant is also unable to achieve 90% capture efficiency required by EPA's proposed rule (its actual capture efficiency is approximately 80%).

- One project that EPA's analysis neglected was the failed Kemper CCS project in Mississippi. This EGU, which cost approximately $7.5 billion to construct, was designed to capture approximately 65% of the plant's CO_2 emissions using a pre-combustion system, was abandoned due to substantial cost overruns, and was never operated. Tennessee acknowledges that the Kemper project was different from Boundary Dam and Petra Nova based on technology differences, and Kemper's construction delays and cost overruns may be explainable by site-specific factors. However, even if the Kemper project had been completed on time and under budget, the plant's 65% capture efficiency, could it have been achieved, would still have been far below the rate required by EPA's proposed BSER.

Finally, Tennessee is not aware of any working carbon capture for simple cycle or combined cycle natural gas plants. In many ways, gas-fired turbines are not substantially different from coal plants, but EPA should not simply assume that coal technology is transferrable to natural gas, EPA must consider factors such as the CO_2 emission rate (gas plants emit roughly half as much CO_2 per unit of electricity output compared to coal plants) and startup/shutdown frequency. These factors, along with others, may mean that these plants may, likewise, struggle to mean EPA's mandated capture efficiency.

Carbon Transport and Sequestration

Transport and storage of CO_2 currently occurs on a limited scale. However, the expansion of carbon transport and sequestration to a national, industry-wide scale is orders of magnitude more difficult – the difference between a flight to Europe and a flight to Mars. A flight to Europe requires some planning and a

[3] Steam reforming of methane produces a smaller volume of waste gas stream with a higher CO_2 concentration, and Tennessee expects that these plants to have capital and operating cost advantages relative to coal-fired power plants.

modest outlay of cash, but a flight to Mars requires a massive capital investment and the assumption of extraordinary risk. Because a small carbon transport and storage network demonstrates that a flight to Europe is possible, EPA presumes a flight to Mars is justified. In reality, the infrastructure for carbon transport and sequestration does not exist at the required scale, the availability of sequestration sites is likely constrained by geography, and the industry-wide application of carbon sequestration is not adequately demonstrated.

Transport of liquified or supercritical CO_2 will require an unprecedented expansion of the CO_2 pipeline system over the next twenty years. EPA states that 5,339 miles of CO_2 pipelines were in operation in 2021, but there were approximately 1,153 facilities generating electricity in 2022, and if each facility requires (on average) 50 miles of pipeline transport to the nearest CO_2 storage site, then about 57,500 miles of CO_2 pipeline would need to be constructed by 2040 – a tenfold expansion of the existing network[4]. The distance from an individual power plant to a viable storage site will vary, but it is undebated that the expanded transport and storage network will need to be much larger than the existing network. EPA's proposed BSER assumes that states, utilities, and pipeline owners can achieve the required expansion of the CO_2 pipeline network over the next two decades, but the on-the-ground reality of pipeline construction is likely to be far more challenging.

Siting issues, landowner rights, impacts on disadvantaged communities, and eminent domain are already controversial issues with respect to pipelines, and EPA fails to consider that most pipeline projects are subject to Federal Energy Regulatory Commission (FERC) jurisdiction, and FERC oversight works to resolve many of the issues related to natural gas pipeline siting and eminent domain. Siting of CO_2 pipelines is not regulated by any Federal agency and there is no federal eminent domain for CO_2 pipelines. Siting is currently

[4] Tennessee's written comments to EPA estimated the size of the required pipeline network based on a distance of 100 miles to the nearest sequestration site. EPA's *Federal Register* notice estimated that most post-2030 coal plants would be within 50-62 miles of a sequestration site. While we cannot assess the accuracy of EPA's estimate, Tennessee's intention was to estimate the nation's CO_2 pipeline needs based on EPA's representation, and 50 miles is more representative of our original intention.

left to States, which may have different standards in addition to various property and right-of-way distinctions that are likely to slow the pace of CO_2 pipeline construction.

The Department of Transportation, as delegated to the Pipeline and Hazardous Materials Safety Administration (PHMSA), regulates construction standards and safety aspects of CO_2 interstate pipelines. Safety concerns with these pipelines have led communities to advocate against the citing of this critical infrastructure under EPA's rule proposal.[5] Further, PHMSA announced it would take steps to implement new measures to strengthen its safety oversight of CO_2 pipelines as a result of its investigation into a CO_2 pipeline failure in Satartia, Mississippi in 2020.

With respect to sequestration of CO_2, EPA asserts that geologic sequestration potential for CO_2 is widespread and available throughout the U.S. in deep saline formations, unmineable coal seams, and oil and gas reservoirs, and that this storage capacity can readily accommodate the amount of CO_2 for which sequestration could be required under the proposed rule. However, sequestration potential is constrained by geography, and these billions of tons of potential sequestration capacity accomplish nothing if EGUs within a specific state lack access to sequestration sites. Tennessee's existing knowledge of sequestration potential indicates that within our own state, sequestration potential is limited to only one type of geologic storage unit (deep saline formations), is confined to one area of the state (Middle Tennessee), and that the state has only eight years of storage capacity based on 2010 emission rates. Power plants in Tennessee may have access to carbon sequestration resources in neighboring states, but we have limited ability to assess those sites, and nearby sites in some states (Kentucky, Virginia, or North Carolina) are likely to encounter many of the same geologic challenges identified in our own state. Further, confirmation and characterization of potential sequestration sites is likely to require several years of work, time that is not included in EPA's compliance

[5] "How Midwest Landowners Helped to Derail One of the Biggest CO_2 Pipelines Ever Proposed," Inside Climate News, Nov. 5, 2023, *available at* https://insideclimatenews.org/news/05112023/landowners-fight-co2-pipeline-midwest-navigator/.

timeframe.

Finally, Tennessee observes that EPA's permit process for Class VI Underground Injection Control wells appears to be moving at a slow pace. The proposed rule states that EPA is currently reviewing permit applications for proposed sequestration sites in at least seven states, but permits have been issued for only two of the 77 UIC Class VI permit applications on EPA's website. Carbon sequestration cannot occur if storage sites remain unpermitted, or if permitting moves too slowly.

Other comments

State and local air programs are EPA's partners in the implementation of the Clean Air Act, bringing our lengthy experience and expertise in implementing federal rules as well as developing plans to comply federal rules and standards. Open and meaningful engagement is critical to the success of this partnership. While EPA did engage with its partners on the rule proposal, much of the engagement was one-sided, whereby EPA asked for thoughts and did not provide specific responses to questions. Once the proposed rule was signed by the Administrator on or about May 11, 2023 and published in the Federal Register on May 23, 2023, the deadline for comments from all parties was July 24, 2023 (later extended to August 8, 2023). This gives interested parties about 90 days to review both the rule and the docket and to prepare their comments. While EPA's notice and comment period complies with the public participation requirements of the Clean Air Act and the Administrative Procedure Act, the docket for this rulemaking is substantial, and in practice, EPA publishes a massive volume of information and provides far too little time for a comprehensive review of such materials. Most importantly, EPA failed to embrace its partner relationships or consider peer federal agency expertise. In doing so, it has not met its own standard for meaningful engagement as applied to state and local agencies in various recent rulemaking proposals, including this one, as well as grant opportunities.

Conclusion

The U.S. power sector is unique in that EPA identifies it as both a key contributor to climate change and a key component of the solution to reduce greenhouse gas emissions. However, any solutions must be undertaken in accordance with the provisions of the Clean Air Act. EPA correctly notes, "The central requirement is that the EPA must determine the 'best system of emission reduction . . . adequately demonstrated,' taking into account the cost of the reductions, non-air quality health and environmental impacts, and energy requirements,"[6] but the proposed rule fails the first, and most important, component of BSER. Neither the proposed requirement to use low GHG hydrogen as fuel nor the requirement to install carbon capture and storage meets the requirement that BSER be adequately demonstrated, using the same legal standards that EPA applies in the proposed rule. The actions that the EPA proposes are inconsistent with the requirements of CAA Section 111 and its regulatory history and caselaw.

I appreciate the opportunity to appear before this Committee. Thank you for the interest you have shown in this important topic. I look forward to answering any questions you may have.

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[6] CAA Section 111(a)(1).