August 7, 2023

EPA Docket Center
United States Environmental Protection Agency (U.S. EPA)
Attention Air Docket ID: EPA–HQ–OAR–2023–0072
Mail Code 28221T
1200 Pennsylvania Avenue, NW
Washington, DC 20460

Dear Administrator Regan:

The State of Indiana appreciates the opportunity to provide comment on the United States Environmental Protection Agency's (U.S. EPA) proposed rulemaking 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." (May 23, 2023, 88 Fed. Reg. 33240)

Indiana has prepared comments that are outlined in the following paragraphs. These comments largely focus on areas where Indiana seeks clarity regarding state rule development and implementation. Indiana respectfully requests that U.S. EPA take into consideration these comments when crafting the final rule.

<u>State Rule and State Plan Revisions</u>
The key component of a State Plan is the enforceable mechanism establishing requirements that apply to affected facilities. In Indiana, the enforceable mechanism is a state administrative rule that is permanent and state enforceable. To adopt a state rule of this complexity, the administrative process is a minimum of 24 months, but with a scope of this magnitude and involving many stakeholders, the process can easily take up to 36 months. The biggest time constraint to start a rulemaking in Indiana is identifying cost impacts up front and completing necessary approvals from the Office of Management and Budget. Indiana requests that U.S. EPA extend the deadline for submissions of State Plans from 24 months to 36 months.

Indiana envisions developing a state rule that would apply broadly to all affected facilities and include all necessary components; including multi-pathway compliance options and requirements to cease operation by specific dates. Subcategory identification for each unit would not be hard coded into the rule. If an applicable unit was not identified during the rulemaking process or applicability subcategory changes, the unit would still be subject to the requirements. The reason for a rule that outlines the requirements for each type of unit without identifying the specific unit, is that any revision to a State Rule will require the state to go through another administrative process of 2 to 3 years to complete.

Indiana understands that one component of the State Plan is identification (40 CFR 60.5740b(1)) of affected electric generating units (EGUs) including identification of the applicability subcategory (such as, long-term existing coal-fired steam generating unit). While this is an important part of the State Plan for transparency and planning purposes, Indiana does not believe this is a component of the State Plan that needs to be revised and approved by U.S. EPA with each change. The plans submitted to meet increments of progress and the transparency provided by the Carbon Pollution Standards website provides sufficient notification (or similar state electronic filing system). This is an inventory component, not a compliance related component of the State Plan. Indiana requests that U.S. EPA provide clarity on what constitutes a State Plan revision and requires approval. Surely U.S. EPA recognizes that multiple State Plan revisions would be resource intensive at both the state and federal level.

Remaining Useful Life and Other Factors (RULOF)

How does U.S. EPA envision use of the Remaining Useful Life and Other Factors (RULOF) provision? Units required to operate carbon capture and sequestration/storage (CCS) may have issues with implementation that may not have been identified until after submission of the State Plan. In State Implementation Plans (SIPs) under Section 110 of the Clean Air Act, sources can request site specific reasonably available control technology (RACT) alternative requirements that are approved by the State and U.S. EPA. Similarly, as part of the State Rule language, could states allow sources to request a RULOF alternative for state and federal approval after submission of the initial State Plan? RULOF provisions will be important as issues arise with grid reliability, and RULOF will also provide the necessary mechanism to approve delays/changes in compliance.

Another way to reduce the need for compliance related changes is to have compliance dates for closure or control on a similar timeline or have the closure date precede the date for compliance with performance standards. A medium-term coal steam generating unit should not be required to co-fire natural gas by 2030 before the closure date of an imminent term unit in 2032. Extending the compliance date for co-firing natural gas would provide greater flexibility for sources making compliance decisions.

Indiana regulated utilities are required to employ an integrated resource planning process that works to optimize reliability and affordability. These plans aim to balance the existing usefulness of ratepayer supported resources with the timely transition to replacement resources over a 20-year review horizon. The use of state sanctioned utility specific planning as support for reasonable alteration of compliance dates should be considered a reasonable means of providing reliable electric service at affordable rates.

Timing for State Plans and Compliance Deadlines

If Emission Guidelines are finalized in mid to late 2024, State Plans with a final and effective corresponding state rule are due in mid to late 2026. This gives sources a little over 3 years to comply by the close of business on December 31, 2029. Three years is a traditional compliance timeframe when considering traditional control devices. It is not an appropriate expectation for Carbon Capture and Storage (CCS) operating at a 90% on-going performance standard. It is impossible considering the right-of-way authorizations, Class VI well permits (and other required permits), pipelines, and troubleshooting the capture system once it is installed for continuous operation.

In addition, the preparation of integrated resource plans is an intensive and time-consuming exercise to better understand the range and implications of resource and compliance options when dealing with pervasive uncertainty. Integrated resource plans take 1-2 years to prepare and are required to be done, at least, every three years. Developing and analyzing compliance plans for a timeline 6 years out is unrealistic when so little is known about the performance and costs of different compliance actions. Recent history should give one pause to consider whether replacement resources or compliance actions can be accomplished by set dates. Also, the utility planning process must consider actions being planned and implemented across a large multistate region if reliable service is to be maintained. Reliability goes beyond the individual utility or state.

Moreover, Indiana regulated electric utilities would also need to petition the Indiana Utility Regulatory Commission for approval and cost recovery for the types of projects that the U.S. EPA is proposing to require. Such proceedings are typically done prior to or near that time of compliance and could add another 4-12 months to the utility's compliance timeline, depending on the type of project, including whether it's a new generation project, and whether financial incentives are being sought – see, for example, Indiana Code section 8-1-2-6.8, chapter 8-1-8.4, section 8-1-8.5-5, and chapter 8-1-8.8.

Natural Gas Co-fire and BSER

The requirement for co-firing with 40% natural gas by 2030 for interim coal steam units is not a Best System of Emissions Reduction (BSER). Did U.S. EPA evaluate whether it was more cost-effective to fully convert these units to a natural gas fired boiler? Was it taken into consideration that natural gas can be burned more efficiently in a combined cycle steam turbine unit and produce more electricity for the same amount of natural gas consumed? Indiana is also concerned that the 50% capacity factor limit could discourage burning of natural gas in a combined cycle steam turbine at a particular unit. While this proposal inherently promotes fuel switching from coal to natural gas, it appears that it does so in a manner that increases overall CO2 emissions from the combustion of natural gas per megawatt-hour.

Indiana also has concerns regarding the transmission and distribution of hydrogen and its impact if used or combined in existing natural gas pipelines and systems, as well as the unknown impact on existing natural gas plants and their equipment, as well as other natural gas customers and their appliances. It's not clear whether U.S. EPA's proposed rule would require hydrogen to be mixed into existing natural gas pipelines and distribution systems or whether entirely new hydrogen-only pipelines and distribution systems would need to be built. While the Pipeline and Hazardous Materials Safety Administration (PHMSA) currently regulates hydrogen-only pipelines, it does not appear to have safety standards or rules for pipeline facilities that would contain, and transport hydrogen mixed with natural gas. The Pipeline Safety Division of the Indiana Utility Regulatory Commission has been certified by PHMSA to enforce federal and state pipeline safety standards and has concerns about corrosion and other issues with hydrogen being mixed into natural gas pipelines. As a result, we do not support the idea of mixing of hydrogen and natural gas until such time as more research has been performed on how the blends affect the lower and upper explosive limits, the permeably characteristics of the hydrogen with plastic piping and existing components, and the long-term effects it could have on existing infrastructure.

In addition, Indiana has encouraged the replacement of aging electric and natural gas infrastructure by statute, specifically Indiana Code chapter 8-1-38 on transmission, distribution, and storage system improvements. As a result, Indiana gas operators have worked diligently to replace aging infrastructure, such as bare steel pipes, with over $1.4 billion dollars in planned projects to date. If hydrogen is required to be introduced into those natural gas systems, then additional, expensive replacements and upgrades will likely be required, over and above what has already been done, at even greater expense to Indiana ratepayers.

<u>Cross Facility Averaging for Co-Firing and Capacity Factor</u>
Indiana requests that U.S. EPA allow for cross facility averaging when calculating compliance with the requirement for co-firing 40% natural gas at coal-fired steam generating units.

To help address concerns with grid reliability and cost-efficiency, the applicability limits on capacity factors should be applied across the facility and not to each unit (cross facility averaging). A facility could have a unit down for maintenance for an extended period and may need to operate another unit greater than the 50% of the capacity factor limit. Other options could be to save up the capacity factor to use in a critical year when it is needed by allowing for a multi-year average and/or add a safety-valve provision to address these emergency situations. The hours of operating during these events would be exempt from demonstrating compliance with the 50% capacity factor limit.

<u>90% CCS Not Adequately Demonstrated</u>
While U.S. EPA cites demonstration projects for CCS, the projects cited do not show 90% capture over an extended period. U.S. EPA also fails to consider the parasitic energy load for CCS of 20-50%. CCS is costly and prone to maintenance issues. It

does not show continued CO2 reduction over a sustained amount of time. Since CCS is not adequately demonstrated as a BSER, it could lead to coal plant closures on a timeline that is not conducive to providing reliable electricity in the long term. A compliance date for long term coal steam generating units of January 2030 to install and operate CCS is simply not realistic.

When exploring the possibility of installing and deploying CCS at its Edwardsport Integrated Gasification Combined Cycle (IGCC) facility, Duke Energy Indiana (DEI) found the site was unsuitable for carbon storage, requiring the Company to explore another site for long term storage of captured CO_2. In 2009, DEI asked the Indiana Utility Regulatory Commission (IURC) to approve approximately $121 million for a carbon storage study that would take about 3 years to conduct.[1] While the Commission ultimately denied DEI's request, utilities may find themselves in similar situations when attempting to site and construct new gas generation. It is best to construct new generation where the existing transmission infrastructure can support it. But if suitable locations to sequester carbon do not exist near transmission lines, it may become infeasible to construct the new gas generation necessary to support grid reliability and resilience. The only two Class VI wells that have been approved in the U.S. needed approximately 6 years to complete the permitting process. As DEI's situation shows, this timeline could be delayed further for utilities and generators that must explore more than one location for carbon storage.

Low GHG Hydrogen Not Adequately Demonstrated

Indiana is not aware of any current or planned projects in the state that meet the low GHG hydrogen requirements. Without the needed infrastructure to provide low greenhouse gas (GHG) hydrogen to the affected facilities in the timeframe required by this rule it cannot be adequately demonstrated or Best System of Emissions Reduction (BSER). Without current projects to evaluate the costs associated with low GHG hydrogen it cannot be determined if it is a cost-effective way to control CO2 or whether it is feasible compared to other control methods of producing electricity. Even if capacity is developed in time to support implementation, the cost is impossible to project. There could be high demand and a minimal supply, which could easily lead to costs far greater than predicted and place undue burden on rate payers.

In addition to the technological and infrastructural constraints of gas generators co-firing hydrogen at the levels the rule proposes, to certify that hydrogen supplied to a combustion turbine was "green," a hydrogen producer would be required to hold and retire enough Renewable Energy Certificates (RECs) to cover the energy it used in producing its hydrogen. IDEM and other state environmental permitting agencies would need to create rules and a system to verify the hydrogen producer secured and retired enough high-quality RECs to supplement the energy it used in the process. This is particularly difficult if the hydrogen producer is not the same entity as the generator, as the generator would likely not have access to the hydrogen producer's energy usage. IDEM and many state environmental permitting agencies are likely not equipped with the

[1] Indiana Utility Regulatory Commission, Cause No. 43653, Final Order (Decided January 23, 2013).

knowledge or resources to create a system to certify, track, and retire RECs associated with hydrogen production and generation. State agencies would need further guidance from the U.S. EPA as to what RECs would be acceptable for compliance, including the appropriate vintage and locational requirements.

Finally, placing the additional requirement on hydrogen to be produced from renewable resources will add a premium to the fuel supplied, as the cost to procure RECs would be passed through the cost of hydrogen. The most affordable RECs on the market currently are found in the national voluntary market. Prior to 2020, voluntary RECs were trading below $1.00/MWh. However, as corporations began implementing sustainability initiatives, demand for unbundled RECs grew, and market prices surged to $7.00/MWh by the end of the summer 2021. While voluntary REC market prices have since stabilized to around $3.00 - $4.00/MWh, requiring gas generators to co-fire with “green” hydrogen will place an upward pressure on the demand for RECs and increase REC market prices. This, in turn, will lead to higher generation fuel costs that will be passed onto electric ratepayers.

<u>Environmental Concerns Must Be Balanced with Reliability</u>
Continued reliability of the electric generation and transmission systems must be an important consideration as the U.S. EPA moves forward with its proposed rule. The Indiana General Assembly established a balanced approach to electric generation in Indiana Code section 8-1-2-0.6, which declares that it is the continuing policy of the State of Indiana “that decisions concerning Indiana’s electric generation resource mix, energy infrastructure, and electric service ratemaking constructs must consider” the following attributes (commonly referenced as the “Five Pillars”):

1) Reliability,
2) Affordability,
3) Resiliency,
4) Stability, and
5) Environmental sustainability

While it is understandable that U.S. EPA’s main concern is environmental, the elimination of too much electric generation too quickly may cause even greater issues, affecting the other key attributes needed for electric generation. The Midcontinent Independent System Operator is estimating that 20 gigawatts of coal electric generation, which is currently not set to retire until after 2040, would fall under this proposed rule and likely be forced to retire much more quickly than expected. The proposed rule expects that new and emerging technologies will develop in time, but what happens if they don’t materialize as expected or within the timelines laid out in the proposed rule? At a minimum, the proposed rule should be adjusted to allow for a safety valve to assure continued reliability.

In addition, the unknown increased costs of imposing the proposed rule as currently written will greatly affect the affordability of electricity, an essential and foundational need for all residents and businesses.

Additional Timing Considerations for Indiana Generation Planning

Before constructing, purchasing, or leasing new generation facilities in Indiana, regulated electric utilities must first go through a pre-approval process and obtain a Certificate of Public Convenience and Necessity (CPCN) from the IURC.[2] Depending on the size and type of generation, this process can take up to 240 days once the utility has initiated the filing.[3] IURC General Administrative Order 2023-03 also requires utilities to provide the Commission with a 30-day notice prior to filing a petition for a CPCN. As part of its determination in awarding a CPCN for new generation, the Commission must find that the utility's proposal is consistent with the utility's most recent Integrated Resource Plan (IRP).

Regulated Indiana electric utilities must submit IRPs to the Commission every three years, but a utility can file an updated IRP sooner if the utility determines it is necessary to re-evaluate its resource needs. As part of developing their IRPs, utilities are required to engage in a stakeholder process where they must hold at least 2 public meetings to allow ratepayers and other stakeholders to ask questions about and provide input into the resource modeling process and assumptions. Depending on the number of stakeholder meetings the utility chooses to hold, this process usually takes 6 months to one year for a utility to complete. The entire IRP procedure from the start of the stakeholder process to receiving the IURC IRP Director's final report generally takes about 2 years to complete.

While all of Indiana's investor-owned utilities have made significant progress to acquire and construct new renewable generation to replace retiring coal generation, many utilities have identified the need for new gas generation by 2028 to support the substantial amount of renewable capacity they are adding to their generation portfolios. Due to Indiana's comprehensive resource planning and pre-approval process in combination with the long lead time to site, permit, and construct new generation, a utility needing new gas generation would need to begin this process within the next 2 years to secure the capacity it needs after 2028. As previously noted, CCS deployment and hydrogen availability are not advanced enough to provide adequate time or assurance these technologies can be deployed by the time new gas generation is needed after 2028. Utilities may be forced to choose between delaying the construction of needed generating resources (and failing to meet future reliability requirements) or building gas generation without the guarantee that it will be able to operate in compliance with the new standards. This could lead to significant utility stranded costs that would be passed on to ratepayers.

[2] Ind. Code ch. 8-1-8.5.
[3] Ind. Code §8-1-8.5-5(b).

Indiana appreciates the opportunity to provide comment to U.S. EPA on this proposed rulemaking. Indiana appreciates U.S. EPA taking these comments into consideration as the rulemaking process moves forward and a final rule is promulgated. If you have any questions concerning these comments, please feel free to contact Matt Stuckey, Assistant Commissioner of IDEM's Office of Air Quality at (317) 233-0243, or mstuckey@idem.IN.gov.

Sincerely,

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