Indiana ENERGY Association

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January 21, 2016

The Honorable Gina McCarthy, Administrator
U.S. Environmental Protection Agency
1200 Pennsylvania Avenue, NW
Washington, DC 20460

Re: EPA-HQ-OAR-2015-0199
Sent via Federal eRulemaking portal

Dear Administrator McCarthy:

The Indiana Utility Group ("IUG") is comprised of Indiana power providers, including investor-owned utilities, electric cooperatives, and municipal power companies. IUG provides the attached comments to the U.S. Environmental Protection Agency for the Federal Plan Requirements for Greenhouse Gas Emissions from Electric Utility Generated Units Constructed on or Before January 8, 2014; Model Trading Rules; Amendments to Framework Regulations; Proposed Rule. 80 Fed. Reg. 64,966 (October 23, 2015).

Currently, IUG's members are:

Hoosier Energy
Indiana Energy Association
Indiana Municipal Power Agency
Ohio Valley Electric Corporation
Wabash Valley Power

As mentioned in these comments, we have also attached the comments our organization filed with U.S. EPA on November 25, 2014 regarding the proposed Clean Power Plan.

We appreciate the opportunity to participate in this important rulemaking.

Sincerely,

Mark T. Maassel

Mark T. Maassel
President
Indiana Energy Association
On behalf of the Indiana Utility Group

Attachments: January 20, 2016 IUG comments
November 25, 2014 IUG comments

Comments by the Indiana Utility Group
on the
U.S. Environmental Protection Agency's Proposed
Federal Plan Requirements for Greenhouse Gas Emissions from Electric Utility Generating Units Constructed on or Before January 8, 2014; Model Trading Rules; Amendments to Framework Regulations; Proposed Rule

80 Fed. Reg. 64,966 (October 23, 2015)
Docket ID No. EPA–HQ–OAR–2015–0199

January 21, 2016

Introduction

The Indiana Utility Group ("IUG") is comprised of Indiana power providers, including investor-owned utilities, electric cooperatives, and municipal power companies. Together, the Group's members employ more than ten thousand people, pay hundreds of millions of dollars in annual taxes, and donate millions of dollars to local, state, and national philanthropic causes. The mission of these companies is to continue providing reliable service to Indiana's electricity and gas customers at some of the lowest overall rates in the nation.

IUG is pleased to have the opportunity to comment on the proposed Federal Plan and model trading rules as published in the Federal Register on October 23, 2015. 80 Fed. Reg. at 64,966. IUG was also pleased to comment on the proposed Clean Power Plan (CPP). Because of the close relationship between this proposal and the CPP, we attach a copy of our November 25, 2014 comments on the proposed Clean Power Plan and incorporate them into these comments by reference.

1. Legal challenges to EPA's Clean Power Plan

Before providing comments on specific elements of the U.S. Environmental Protection Agency's ("EPA" or "the agency") proposed Federal Plan Requirements for Greenhouse Gas Emissions from Electric Utility Generated Units Constructed on or Before January 8, 2014; Model Trading Rules; and Amendments to Framework Regulations ("Federal Plan"), IUG

emphasizes its objection to key components of both the Section 111(b) and Section 111(d) final rules that the agency announced on August 3, 2015 as the CPP. IUG has joined with many States and other interested parties in filing petitions for judicial review before the U.S. Court of Appeals for the District of Columbia Circuit, challenging both the 111(b) and 111(d) rules as components of the CPP.

There are numerous legal objections to the CPP and to the proposed Federal Plan, which would be invoked in the event States do not submit plans that meet the requirements of the CPP. While we will not attempt to identify all of the possible legal defects in the CPP and the proposed Federal Plan, we do call attention to five areas below.

a. Absence of clear congressional intent.

The authority underlying the proposed Federal Plan is Section 111(d) of the Clean Air Act. However, the proposal does not so much regulate emissions from fossil-fueled power plants, but rather, imposes broad-based energy policy measures specifically aimed at reducing the demand for fossil-fueled power generation with the approach that is preferred by the agency. EPA's proposed Federal Plan is an unprecedented regulatory stretch beyond the CAA and Congressional authorization into the world of energy policy development and implementation.

The proposed Federal Plan represents significant policy questions that have not yet been addressed by the Congress. The U.S. Supreme Court addressed this point in *UARG v. EPA,* 134 S. Ct. 2427 (2014) as follows:

> "When an agency claims to discover in a long-extant statute an unheralded power to regulate a significant portion of the American economy, we typically greet its announcement with skepticism. We expect Congress to speak clearly if it wishes to assign an agency a decision of vast economic and political significance."

Nothing in Section 111(d) can be argued to empower EPA to set the nation's energy policy, and the agency's attempt to do so must necessarily fail.

b. Section 112 Exclusion.

Even if EPA were authorized to regulate energy policy — a conclusion that we do not accept — the agency is prevented from doing so in this instance concerning existing electric generating units (EGUs) because of the section 112 exclusion. The Clean Air Act obligates EPA, under Section 111(b), to develop a list of categories of stationary sources and propose regulations for new sources within such categories. On the other hand, section 111(d) acknowledges that there are existing sources that have a remaining useful life, for which States shall submit a plan establishing standards of performance for any existing source.

However, there are qualifiers in the statute as to which existing sources are to be targeted by this existing source State plan. Section 111(d) says that EPA may not require States to develop an existing source performance standard for any air pollutant emitted from a source category that is regulated under Section 112 of the CAA – the Section 112 Exclusion.

Section 112 of the CAA is a provision requiring EPA to review the statutory list of hazardous air pollutants ("HAPs"), revise as appropriate, and develop a list of source categories that emit HAPs. A new HAP may be added to the list when EPA determines that a pollutant may present "a threat of adverse human health effects" "through inhalation or other routes of exposure" or "adverse environmental effects whether through ambient concentrations, bioaccumulation, deposition, or otherwise." For electric utility steam generating units ("EGUs"), the statute requires EPA to study the "hazards to public health reasonably anticipated to occur as a result of HAPs emitted from power plants before EPA determined whether to list them under section 112."

The 1990 amendments to the CAA resulted in modification to the Section 112 exclusion. Congress amended the exclusion to prohibit EPA from requiring States to regulate under Section 111(d) the emission of "any air pollutant . . . emitted from a source category which is regulated under section 112." Pub. L. No. 101-549, §108, 104 Stat 2399 (codified at 42 U.S.C. §7411(d)(1)). The intent of Congress was to avoid duplicative regulation of existing source

categories by not allowing EPA to require State-by-State regulation of an existing source category under Section 111(d), when that category already had to comply with the national emission standards of Section 112. In considering the amendment, Congress was concerned about the feasibility of existing sources complying with Section 112's stringent requirements and also regulation imposed by States under Section 111(d).

Because EPA has already chosen to regulate fossil-fueled power plants under Section 112, it may not do so under Section 111(d), as the agency seeks to do under this proposal.

c. Standards of performance.

Section 111(d) authorizes EPA to direct States to establish "standards of performance for any existing source," under certain circumstances. 42 U.S.C. §7411(d)(1)(A). A "standard of performance" is "a standard for emissions of air pollutants which reflects the degree of emission limitation achievable through the application of the best system of emission reduction ["BSER"]." 42 U.S.C. §7411(a)(1). EPA lacks the authority to define the BSER in a manner that goes beyond improvements available at an individual source.

By developing the BSER for CO_2 reductions in existing fossil-fueled power plants, as EPA has done in the proposed Federal Plan, the agency requires EGUs to use "outside the fence line" measures, such as switching to use of alternative fuels or generation technologies, and/or requiring dramatic reductions in electricity usage. This is particularly well-illustrated by the proposed rate-based Federal Plan, which is built on the premise that emission reduction credits ("ERCs") are generated by activities that do not emit CO_2, and only to a limited extent on activities that occur at the affected facilities themselves. This is an egregious expansion of EPA's authority into areas where the agency lacks expertise or jurisdiction. The Federal Plan may not, as a matter of law, reach beyond the CAA authority to require standards of performance, design improvements, or operational advances for the purpose of reducing the usage of coal-fired energy.

Moreover, the proposed Federal Plan provides for the implementation of an emission standard on existing sources under the Section 111(d) that is more stringent than the standard set for a new source under Section 111(b). An error of this nature points to the arbitrary character of the proposal.

d. Arbitrary and capricious decisions by EPA.

EPA may not engage in national policy development without appropriate public input or in lieu of Congressional authority. Nevertheless, EPA arbitrarily increased the CO_2 emissions reductions called for in the proposed Clean Power Plan for Indiana and several other states when the agency promulgated the final Clean Power Plan rules.

EPA's June 2014 Clean Power Plan proposal would have required Indiana to reduce carbon dioxide emission from EGUs located in the State by 20%. The final rule requires carbon dioxide emission reductions from Indiana EGUs of 39%.

EPA offered little justification for the difference between the proposed and final rules in regard to CO_2 emissions reductions, nor did the agency offer an opportunity for public review and additional comment about such dramatic changes in the level of these emissions cuts. Other states will suffer under EPA's bait-and-switch tactics as well. For example, West Virginia's CO_2 reductions soared from 19% in the proposed Clean Power Plan to 36% in the final rule, Kentucky's reductions from 18% to 39%, Iowa from 16% to 41%, and North Dakota from 10% to 44%. A doubling of emissions reductions levels —or more— without providing a substantive opportunity for review of the technical and policy rationales for such action resulted in a rule that is both arbitrary and capricious.

Further, EPA's actions violate the Administrative Procedures Act, as evidenced by the lack of technical justification, as well as the failure to provide public notice and the opportunity for comment. The agency's actions consequently run afoul of the fundamental protections of due process, as detailed in section 11 ("Finalizing the Federal Plan") below. Accordingly, EPA must

withdraw the Clean Power Plan, since it was not a "logical outgrowth" of the proposed rule. *CSX Transportation, Inc. v. Surface Transportation Board*, 584 F. 3d 1076, 1079-1080 (D.C. Cir. 2009)

e. Impermissible constraint on State authority.

EPA requests comment on its disregard of a State's ability to seek a different emission standard from the agency under the provisions of 111(d). It is improper for EPA to assert that the agency has the authority to press upon States the obligation to reorganize their intrastate generation and consumption of electricity, as set forth in this proposed Federal Plan. EPA's BSER Building Blocks 2 and 3 require States to change their energy generation and consumption by reducing reliance on coal fired-generation in favor of natural gas and renewable sources.

Thus, the proposed Federal Plan is a violation of the Tenth Amendment, which provides, "The powers not delegated to the United States by the Constitution, nor prohibited by it to the States, are reserved to the States, respectively, or to the people." EPA is not empowered under the Clean Air Act, or otherwise, to require the States to implement such energy policies.

These are but five of the consequential faults that the CPP contains. In light of these and other defects, IUG believes the U.S. Court of Appeals for the District of Columbia Circuit will strike down the Clean Power Plan.

Similarly, EPA's proposed Federal Plan contains many, serious flaws. These errors undercut the efforts of IUG members, as well as the owners and operators of power plants across the nation, to provide a reliable supply of low-cost energy to our consumers. IUG offers our comments on specific elements of the proposed Federal Plan, and we urge EPA to cure the flaws identified below — in case the Clean Power Plan survives federal court scrutiny.

2. Reliability safety valve

The 111(d) final rule within the Clean Power Plan contains a "reliability safety valve" ("RSV"). The proposed Federal Plan rejects such a mechanism, although the EPA requests comments on this position, along with comments about developing a reliability set-aside for allowances under a mass-based Federal Plan for use in emergencies. IUG strongly supports creating a reliability safety valve in the Federal Plan, as well as in the Clean Power Plan, and suggests that EPA consider creating a reliability set-aside, as discussed further below.

a. Reliability Safety Value.

As noted by EPA in the CPP, circumstances may exist where an affected EGU faces the need to operate in an emergency situation. Serious concerns have been expressed that an unforeseen event could occur during implementation of the final rule requiring immediate, reliability-critical responses by system operators and affected electric utility generating units that would result in unplanned or unauthorized emissions increases.

Deep concerns about the how the Clean Power Plan could undermine electric system reliability have been repeatedly raised by the members of the National Electric Reliability Council (NERC) and the Federal Energy Regulatory Commission (FERC), as well as by many electric utilities, along with regional and State regulators. For example, The ISO/RTO Council ("IRC"), comprised of Independent System Operators ("ISOs") and Regional Transmission Operators ("RTOs") from across the nation, described the importance of a reliability safety valve as follows:

> "The RSV proposal can help to ensure outcomes that address reliability issues without affecting the policies underlying the CO_2 rule compliance design. In 2012, the IRC worked with EPA to establish an enforcement policy related to the MATS rule that reflects the RSV concept. Although the RSV proposal for the CO_2 rule differs slightly, the underlying reliability proposition is the same – allow for electric system reliability impact reviews related

> to compliance requirements and, where relevant, provide for appropriate compliance and/or enforcement flexibility to accommodate solutions to mitigate issues that would otherwise compromise reliability requirements." ISO/RTO Council. "Reliability Safety Valve and Regional Compliance Measurement and Proposals," page 2.

In the final Clean Power Plan rule, EPA accepted the importance of including a RSV, stating, "We, nevertheless, agree with many commenters that it is prudent to provide an electric system reliability safety valve as a precaution." 80 Fed. Reg. 64,671.

Despite the warnings of national, regional, and State regulators, as well as EPA's own declaration in the Clean Power Plan rule, the agency chose to reject a RSV in the proposed Federal Plan by stating:

> "In the final CPP EGs [Emissions Guidelines], the EPA laid out the availability of a reliability safety valve that could be used if an unanticipated catastrophic emergency caused a conflict between maintenance of electric reliability and inflexible requirements that a state plan might impose on an affected EGU or EGUs. Under the federal plan, inflexible requirements are not imposed on specific plants. Rather as explained earlier, the very nature of the federal plan, in which affected EGUs can obtain allowances or credits if needed, supports reliability. Therefore, a reliability safety valve for the federal plan is not needed." 80 Fed. Reg. 64,982.

Notwithstanding the fact that allowances and emission reduction credits can be obtained under the Clean Power Plan, EPA still found it appropriate to establish a reliability safety valve in the CPP. Thus, EPA's bald assertion that "a reliability safety valve is not needed" in the proposed Federal Plan fails to provide justification for the agency's position on this critical issue.

While the EPA brushed aside the importance of creating a RSV in the proposed Federal Plan, Congress does not share that skepticism. As recently as December 4, 2015, Congress spoke to this very issue in the Surface Transportation Reauthorization and Reform Act of 2015. In that legislation, assurances are provided that, if ordered to operate to assure power system reliability, the party would not be considered to be in violation of environmental law or regulation. Orders

to operate shall not exceed 90 days and, if an extension is warranted, further assessment of environmental impact will be conducted. The legislation creates authority to address grid security emergencies and the directive to establish a protocol. These legislative provisions are consistent with the CPP. Since Congress has spoken, we urge EPA to include a reliability safety valve in the Federal Plan.

Further, the North American Electric Reliability Corporation, which has the mission of assuring the reliability of North America's bulk power system, recently issued its *2015 Long-Term Reliability Assessment*. This assessment found that the Midcontinent Independent System Operator ("MISO"), the regional transmission operator serving most of Indiana, projects "that Reserve Margins will continue to tighten over the next five years, approaching the Reserve Margin requirement." NERC's 2015 assessment further found that "operating at the Reserve Margin creates a new operating reality for MISO members where the use of all resources available on the system and *emergency operating procedures are more likely*." (emphasis added) NERC's statement is a clarion call for including a reliability safety valve in the Federal Plan, as EPA prudently did in the Clean Power Plan.

b. Reliability Set-Aside.

As for the need to create a reliability set-aside, we recommend that EPA study the matter in conjunction with FERC, ISOs, and RTOs. At this time, it is not obvious that a set-aside is appropriate with regard to reliability. For example, creating a set-aside from affected EGUs could exacerbate reliability issues. To avoid this issue, EPA should create a separate federal pool of allowances, separate from the State budget, to address local and regional reliability concerns.

As stated by EPA in the CPP, agency perceptions are that little risk exists relative to reliability. Since the facts are yet to be defined in this regard, IUG urges the federal and regional partners listed above to monitor the issue, reserving for another rulemaking whether a reliability set-aside is necessary to assure achievement of the air quality goals.

3. **New Source Review**

By developing Emissions Guidelines ("EGs") within the Clean Power Plan that are based, in part, on assumed heat rate improvements at fossil-fueled power plants, EPA has brought significant concerns about New Source Review (NSR) compliance to the forefront. NSR compliance actions, either by EPA or as a result of citizen suits, are a real threat to EGU owners and operators attempting to reduce CO_2 emissions by improving heat rates — through upgrades to boilers, turbines, heaters, or a raft of other technologies and systems.

Under the provisions of the CPP, EPA asserts that "while there may be instances in which an NSR permit would be required, we expect those situations to be few." *Id.* at 64,985. IUG agrees that technology or system upgrades, such as those described above, to reduce CO_2 emissions in order to comply with the Clean Power Plan or a Federal Plan should not be considered to have triggered NSR. Nevertheless, to eliminate the threat of extended NSR litigation, EPA should a) make a clear statement that any power plant upgrades necessary to fulfill the mandates of the proposed Federal Plan would not trigger New Source Review and b) promulgate appropriate regulatory changes to provide such protection.

4. Mass-based Federal Plan

EPA has asked for comment on a wide range of issues concerning its proposed mass-based Federal Plan.

a. Distribution of allowances.

EPA proposes that a State subject to a Federal Plan "can determine its own approach to distribute allowances, and [EPA] believes that state allocation has important merits." *Id.* at 65,012. IUG supports provisions in a final Federal Plan that would authorize the State of Indiana to distribute allowances created under a mass-based Federal Plan with no limits or constraints;

provided, however, these allowances must be available only to EGUs. Regardless, EPA should notice and seek comment on any Federal Plan the agency intends to impose on a State.

EPA has also asked for comments on several options for distributing allowances. As stated above, IUG recommends that States be authorized to distribute allowances without limits or constraints, other than the requirement that allowances would go only to EGUs.

However, IUG recognizes the possibility that EPA might be called upon to allocate allowances in the event that a State chooses not to do so. Therefore, our remaining comments in section 4.a. related to limits or constraints on allowance allocations are focused solely on allocations that might be made by EPA, in the event a State refrains from doing so.

The central point in regard to allowance distribution by EPA under a Federal Plan remains the same as for States: EGUs have the sole responsibility for complying with a Federal Plan that may be imposed under the Clean Power Plan, so allowances must be distributed only to them. Moreover, IUG supports basing the allocations of emissions on units operating in 2012, which did not retire during that year. We also favor allocations that are perpetual and are provided only to affected units in order to minimize cost to customers and help assure reliability.

IUG strongly opposes the option EPA offers of using of auctions to distribute allowances. Auctions would lead to unnecessarily higher electricity costs to Indiana residents and consumers. Further, EPA declares in the proposed Federal Plan that "if it [EPA] conducts allowance auctions, any revenue from such actions received by the agency must be deposited in the U.S. Treasury under federal law." *Id.* at 65,018. At that point, Congress would have the authority, through the appropriations process, over these funds raised through such auctions and, therefore, would likely nullify EPA's CPP cost-benefit analysis.

IUG also opposes EPA distributing allowances to zero-emitting generation, an option for which EPA requested comments. Distribution of allowances in this manner would not be solely

to fossil-fueled EGUs and would not promote the fundamental policy of providing a reliable supply of least-cost power.

Under the mass-based approach, EPA proposes to allocate most allowances to affected EGUs using a historic data-based approach. *Id.* at 65,016.[1] It is appropriate to allocate allowances to affected EGUs, based on historic data.

Moreover, the allocation of allowances to affected units would not affect the environmental benefits of the final Emission Guidelines or impact the functioning of competitive electricity markets. Allocating allowances to affected EGUs helps to minimize compliance costs by providing the affected unites with the allowances they would need for compliance.

b. Banking of allowances.

EPA proposes that allowances "may be banked for use in any future compliance period, with no restrictions on the use of banked allowances." *Id.* at 65,014. Such banking is proposed to be acceptable for use of Interim Period allowances during the Final Period. IUG fully supports this provision of the proposed Federal Plan.

c. Borrowing of allowances.

Although EPA does not propose to allow allowance borrowing across compliance periods in a mass-based Federal Plan, the agency asks for comment on this concept. IUG supports the ability of EGUs to borrow allowances across compliance periods. This concept would be facilitated by perpetual allowance allocations. While it does not appear that such a borrowing provision has been included in previous EPA regulatory regimes, CO_2 emissions are a global issue and are inherently different from emissions traditionally regulated by the agency.

[1] These comments support the allocation of allowances based on historic data and do not take a position on whether allocations should be based on historic generation, heat input, or emissions data. States are best positioned to determine the potential implications for compliance and the compliance costs of using generation, heat input, or emissions data.

Accordingly, borrowing of allowances would help to achieve two important goals, in the event EPA imposes a Federal Plan. First, borrowing would provide significantly greater flexibility, especially for owners and operators of EGUs in States, such as Indiana, that must grapple with the dramatically greater CO_2 emissions cuts required in the final 111(d) rule than those outlined in the agency's proposed rule. Second, borrowing could help States meet the requirements of section 111(d) to address the remaining useful life of affected EGUs.

EPA's rationales for denying the borrowing of allowance are that 1) determining future allocations would be made more difficult and 2) a State's ability to put its own allowance distribution program in place – rather than relying on an approach established by EPA – would be impeded. EPA also implicitly argues that the environmental integrity of the Clean Power Plan would be undercut by borrowing provisions.

IUG believes that EPA's concerns are misplaced. The State of Indiana could develop its own allowance allocation program and would have ample time to do so, should a Federal Plan be imposed by EPA. Further, the environmental integrity of the Clean Power Plan would not be put at risk by allowing borrowing, since the total emissions reductions mandated under an affected State's CO_2 emissions budget would not be changed. Therefore, the advantages of borrowing allowances to ensure compliance with the Clean Power Plan outweigh any potential administrative complications that borrowing might cause.

d. Allowances from retired EGUs.

As a part of EPA's proposal to address the handling of allowances related to units that retire, the agency has requested comment on several issues. *Id.* at 65,026. IUG believes it to be sound public policy that units, either retired or placed in longer-term storage, should continue to receive allocations. Continuing these allowances would assist the owners and operators of those units to mitigate customer costs and would help to assure reliability.

We also recognize that similar benefits would result from retiring fossil-fueled units before the start of the Interim Compliance Period. Accordingly, we urge that these units also continue to receive allowances.

With respect to the proposal that allowances be reallocated to entities other than EGUs, IUG strongly opposes such proposals. The result of reallocating allowances to non-affected sources would only drive up costs and exacerbate reliability concerns.

While reallocating allowances would reduce the cost of such generation to those entities receiving the allowances, doing so will result in substantial inequities by increasing the costs of the owners of the affected units. Indeed, owners of the retired units will face the irony of being forced to pay for those allowances to be able to use them for compliance purposes. Equity demands that the allowances remain with the retired units themselves.

e. Set-asides that would limit the availability of allowances to EGUs—leakage.

EPA proposes in the Federal Plan to limit the pool of allowances available under a mass-based program by creating "set-asides" for several purposes. The agency proposes creating set-asides to address "leakage," which EPA defines as:

> "The final EGs specify the concern of leakage, which is defined in section VII.D of the final EGs preamble as the potential of an alternative form of implementation of the BSER (e.g., the rate-based and mass-based state goals) to create a larger incentive for affected EGUs to shift generation to new fossil-fired EGUs relative to what would occur when the implementation of the BSER took the form of standards of performance incorporating the subcategory-specific emission performance rates representing the BSER." *Id.* at 65,019.

Maintaining the pool of allowances for EGUs, to the greatest degree possible, will further the goal of providing reliable, low-cost power for Indiana consumers during implementation of the Clean Power Plan. Therefore, since leakage will not occur in Indiana, IUG strongly opposes

the creation of set-asides to address leakage. If EPA decides to move forward with set-asides, we urge the agency to ensure that under-subscribed set-aside allowances return only to EGUs.

f. CCS and allowances

As discussed later in these comments related to ERCs, IUG believes that EPA's recognition of the potential application of carbon capture and storage (CCS) technology to new coal-fired generation — and the fact that CCS is one of a few inside-the-fence options available to EPA — compels the agency to recognize the value of generation equipped with CCS as part of any Federal Plan it may adopt. While it seems unlikely that CCS would be applied to existing sources in the near term, EPA should allow for generation equipped with CCS to be provided with appropriate allowances to encourage its development.

In the event that CCS technology and/or public policy evolve to the point that it becomes justifiable to develop this technology, the Federal Plan should give CCS technology proper recognition for the critical role it would play in allowing the continued utilization of coal and other fossil fuels in power generation.

5. Rate-based Federal Plan

EPA has also asked for comment on a wide range of issues concerning its proposed rate-based Federal Plan. As an initial point, IUG reaffirms our comments in Section 1(c) above ("Standards of performance") about EPA's regulatory overreach in the underpinnings of the rate-based plan. In the Clean Power Plan and the proposed Federal Plan, the agency is attempting to regulate "outside the fence line" by establishing an unjustified "best system of emission reduction." By these actions, EPA claims regulatory authority where none exists within the Clean Air Act or under applicable case law.

Further, for reasons in great part related to administrative convenience, EPA proposes (*Id.* at 64,994) to limit the issuance of ERCs to the following categories:

- affected units with emission rates below applicable limits,
- affected NGC units that achieve applicable capacity factors,
- new nuclear units and capacity uprates at existing nuclear units, and
- renewable energy reserves (utility scale).

IUG is concerned that such a universe of ERC options will severely limit compliance options under the rate-based plan and unnecessarily impose added compliance costs on the consumers of electric power.

EPA has, however, invited comment on whether to limit the scope of the Federal Plan in this manner, and if not, what other sources should be eligible to generate ERCs for compliance purposes. *Id.* at 64,990. For reasons that we set forth below, IUG urges that ERCs be allowed with respect several additional categories of sources.

a. Generation of ERCs.

IUG recommends that a rate-based Federal Plan should allow ERCs to be generated from the same category of options as would be available to the States under the CPP. In addition to the sources eligible to generate ERCs under the Clean Power Plan, States would be allowed to issue ERCs for the following categories, under the model trading rule:

- biomass,
- distributed generation,
- combined heat and power,
- waste heat and power, and
- demand side energy efficiency.

In an effort to keep the cost of this program to consumers of electricity as low as possible and to enhance reliability, we urge that the Federal Plan allow the issuance of ERCs related to all of these categories, as well as to utility delivery system efficiency that results in a net reduction

of CO_2 emissions, and non-EGU projects that result in a net reduction in CO_2 emissions, provided that any ERCs or allowances generated go to EGUs.

b. ERCs and retired units.

EPA has, of course, proposed a program by which the owners-operators of retiring EGUs would be allowed to retain those allowances for a period of time. *Id.* at 65,026. As is stated in our comments about the proposed mass-based Federal Plan, we believe it to be sound public policy that units, either retired or placed in longer-term storage, should continue to receive allocations. Correspondingly, we believe that EPA should provide for a similar program (see details in our comments on allowances for retired EGUs above) to allow for creating ERCs under rate-based programs.

c. CCS and ERCs.

As discussed above in our comments on the proposed mass-based Federal Plan, EPA has recognized the potential application of carbon capture and storage technology to new coal-fired generation and with respect to the type of compliance measures available to States under the CPP. Nevertheless, the agency has not addressed CCS with respect to eligibility for ERCs under the proposed Federal Plan.

While it seems unlikely that CCS would be applied to existing sources in the near term, we believe EPA should provide that generation equipped with CCS would be as eligible for ERCs, as would be the case with either new nuclear or utility scale renewable energy technology.

In the event that CCS technology or public policy evolves to the point that it becomes justifiable to develop this technology, the Federal Plan must give proper recognition to the critical role that CCS technology would play in allowing the continued utilization of coal and other fossil-fuel in power generation.

d. Banking of ERCs.

Consistent with our position regarding banking allowances stated above, IUG also fully supports EPA's provisions in the proposed Federal Plan to allow the banking of ERCs.

e. Borrowing of ERCs.

Also, consistent with our position regarding borrowing allowances discussed above, IUG favors allowing the banking of ERCs, which the proposed Federal Plan would not permit.

EPA has expressed its concern that ERCs could not be borrowed since they would not yet have been generated. *Id.* at 65,010. This concern is not appropriate for two reasons. First, EPA proposes to issue allowances to renewable energy projects, based on projected generation. Similarly, EPA should allow for borrowing of projected ERCs, so long as the generator of the ERCs to be borrowed complies with all other eligibility requirements. Further, owners and operators of EGUs face substantial penalties under the proposed rate-based Federal Plan if they fail to produce the number of ERCs that would bring the EGU into compliance. The risk of these considerable penalties should provide EPA with sufficient security to allow the prudent use of borrowing.

Therefore, IUG urges EPA to allow the borrowing of ERCs to provide additional flexibility for the owners and operators of EGUs in complying with EPA's mandates under a rate-based Federal Plan.

6. Clean Energy Incentive Program

EPA requests comment on all aspects of implementing the Clean Energy Incentive Plan ("CEIP"). Unless otherwise noted, IUG's comments below are applicable to the CEIP within the Clean Power Plan, as well as within the proposed Federal Plan.

Since it is the States that would be opting into the CEIP in the context of a State Plan, all aspects of the CEIP should be determined by the States that join. In addition, EPA proposes that

States subject to the Federal Plan be required to participate in the CEIP, rather than having the flexibility to opt in.

Regardless of whether a State opts in or is required to participate, most States have neither the expertise nor resources to staff the CEIP. IUG, therefore, suggests that EPA consider providing resources necessary to implement the CEIP to any State that participates. If EPA is not able to provide additional CEIP implementation resources, IUG suggests that States be allowed the flexibility to craft their own CEIPs, based on their own resources and subject only to the requirements discussed below.

IUG also firmly believes that no allowances should be taken from a State's emissions budget to implement the CEIP. The allowances for the CEIP program should be in addition to the State's emissions budget, which will also encourage more participation in the program.

IUG strongly believes that the allowances and ERCs from the CEIP program should be available only to EGUs, since EGUs are the entities required to comply with the CPP. Therefore, IUG strongly opposes the EPA option of allowing auctions to distribute allowances. Auctions could allow a third-party to drive up allowance prices and unfairly affect the market by hoarding allowances. Auctions would lead to unnecessarily higher electricity costs to Indiana residents and consumers. In addition, EPA declares in the proposed Federal Plan that "if it [EPA] conducts allowance auctions, any revenue from such actions received by the agency must be deposited in the U.S. Treasury under federal law." *Id.* at 65,018. At that point, Congress would have the authority over these funds through the appropriations process, which IUG asserts is an inappropriate result of a CPP auction process.

Subject to these general comments, and while objecting to narrowing the CEIP by providing for specific CEIP attributes, IUG offers the specific comments below in response to EPA's requests.

a. Criteria for eligible RE and EE projects.

IUG suggests that EPA allow States opting into the CEIP to develop their own eligibility criteria for both renewable energy ("RE") and energy efficiency ("EE") projects. IUG recommends that EPA should broaden CEIP project eligibility to maximize incentives for early action by awarding ERCs or allowances to those eligible projects commencing construction or commencing operation immediately after a State submits its formal intention to participate in the CEIP program.[2] This will incentivize more participation and early action by EGUs within the CEIP program and will allow more time for project planning by the EGUs.

Accordingly, IUG recommends that EPA expand the eligibility criteria to include, at a minimum, projects involving:

- biomass,
- distributed generation,
- combined heat and power,
- waste heat and power,
- utility sponsored demand side energy efficiency,
- utility delivery system efficiency that results in a net reduction of CO_2 emissions, and
- non-EGU projects that result in a net reduction in CO_2 emissions, provided that any ERCs or allowances generated go to EGUs.

b. Definitions for "commence construction" of an eligible RE project and "commence operations" of an eligible low-income EE project.

EPA should adopt the broadest definition of each of these respective terms in order maximize the mission of the CEIP – to incentivize early action.

Clean Air Act Standards of Performance for New Sources at 40 CFR 52.21(b)(1)(ix)(8) and (9) collectively define "commence construction" as:

[2] IMPA's position is that EPA should grant early action credit under the CEIP to those eligible renewable energy projects commencing construction in 2015 to coincide with the promulgation of the CPP, as noted in IMPA's comments to EPA on the CEIP non-regulatory docket at EPA-HQ-OAR-2015-0734-0036.

> (8) "Construction means any physical change or change in the method of operation (including fabrication, erection, installation, demolition, or modification of an emissions unit) that would result in a change in emissions.
>
> (9) Commence as applied to construction of a major stationary source or major modification means that the owner or operator has all necessary preconstruction approvals or permits and either has:
>
> > (i) Begun, or caused to begin, a continuous program of actual on-site construction of the source, to be completed within a reasonable time; or
> >
> > (ii) Entered into binding agreements or contractual obligations, which cannot be cancelled or modified without substantial loss to the owner or operator, to undertake a program of actual construction of the source to be completed within a reasonable time.

IUG suggests that the definition of "commence construction" for RE projects, for the purpose of the CEIP, be consistent with the New Source Performance Standard definition and be either the date of initial on-site project activity or the date on which the project sponsor executes a binding, irrevocable contract for fabrication or construction of the unit.

With respect to "commencing operations" for EE projects, IUG recommends that the definition be limited to projects implemented and/or sponsored by utilities and include the date on which the energy efficient improvement has been installed or started with participating utility customers implemented at a property.

c. Eligible EE projects.

IUG firmly believes that eligible EE projects should not be limited to "low-income communities," regardless of the definition of "low-income community." If the purpose of the CEIP is to incentivize early CO_2 reductions, any project that results in quantifiable, verifiable reduction in either CO_2 emissions or generation demand should be eligible for ERCs.

In order to address the continued need for EE projects in low-income communities, we also recommend that EPA provide double credits for projects sponsored by utilities for properties located in State-determined, low-income communities. Single credits would be provided for projects in all other areas. This would effectively incentivize EGUs to participate in the CEIP program where it makes the most sense in their service territory, while also encouraging more participation in low-income communities.

d. Definition of "low-income community" for eligible EE projects.

If the EPA remains determined to limit the EE portion of the CEIP program to "low-income communities," IUG suggests that EPA allow States the flexibility to define "low-income communities" with the broadest term possible. The definition of low-income community should be geography-based and inclusive of EE projects serving all customer classes (residential, commercial, and industrial) in that area.

For residential customers, specifically, IUG recommends that EPA follow existing low-income program qualifying levels to ease administrative burden, lessen oversight complexity, and maximize low-income community eligibility to create CEIP compliance efficiency. In Indiana, energy assistance and utility-sponsored low-income EE programs are generally available to residential low-income households, up to 200 percent of the federal income poverty level (Department of Health and Human Services).

The use of the 200 percent of poverty guideline is consistent with the existing State of Indiana's weatherization programs. Additionally, individual households that are at or below the federal poverty guidelines, but not located within a low-income community, should be eligible for the CEIP program.

e. EM&V requirements for eligible projects, requirements for M&V reports of quantified MWh, and requirements for verification reports from an independent verifier.

IUG believes that the criteria for CEIP project qualification should be based on either an existing state accepted framework, an industry international standard, or a framework developed by the utility sector.

f. Mechanism for reviewing project submittals and issuing early action allowances or ERCs.

The Indiana Department of Environmental Management (IDEM) currently has no staff with experience in evaluating qualification criteria for RE or EE projects. Further, IDEM has no existing staff available to maintain the required records for the CEIP. Indiana EGUs have both the experience and expertise to assist IDEM in these efforts. Accordingly, IUG requests that EPA allow the flexibility for the EGU sector to be involved in such efforts to support IDEM, at least in the evaluation of projects submitted for ERCs or allowance credits.

g. Timing of allocation of matching allowances or ERCs to a State by EPA, as well as timing awards from these allocations to eligible project providers.

IUG suggests that, consistent with the goal of incentivizing early action, EPA should distribute allowances and ERCs as early as a State Plan is approved or the State is declared to be subject to the Federal Plan.

h. Redistribution method for matching allowances or ERCs that are allocated to a State, but not awarded to eligible projects, as well as the timing for this redistribution.

IUG favors redistribution to EGUs, with no limitations or constraints on States, which would promote the goals of reliable service at the least cost to Indiana consumers.

i. Approach for distributing the 300 million short ton CO_2 emissions-equivalent matching pool among states participating in the CEIP.

IUG recommends that the distribution be linked to the State's pro rata EGU CO_2 emission reduction requirements, so that States with more stringent emission reduction requirements receive more allowances or ERCs from the pool, in order to level the playing field.

j. How to convert the 300 million short ton CO_2 emissions equivalent matching pool into ERCs, which are based on MWh.

IUG believes that the allowances should be converted at a rate of 1.67 ERC/allowance, which ratio takes into account the new source EGU coal-fired emissions guidance of 1200 lbs. CO_2/MWh.

k. *How States, tribes, and territories for which goals have not yet been established in the final EGs may be able to participate in the CEIP.*

States, tribes, and territories, for which goals have not yet been established in the final CPP's Emissions Guidelines, were not included in any EPA calculations of pro rata shares of allowances for distribution purposes. Therefore, IUG suggests that those States, tribes, and territories should be excluded from participation in the CEIP.

l. Mechanism for maintaining the stringency of rate-based emission standards during the compliance period to account for the issuance of early action ERCs for MWh generated or avoided in 2020 and/or 20121.

IUG believes that the CEIP concept necessarily means that rate-based emissions standards will fluctuate according to the ERC/allowance market. The whole point of allowing a market-based system to drive compliance is that the rate-based standard will fluctuate, to a degree. Experience has shown that, doing so, results in faster compliance at a lower cost than would occur without a market-based system in place.

7. Pricing Safety Value on ERCs and Allowances

As EPA, itself, points out in the preamble to the proposed rule (*Id.* at 64,977), the ERC and allowance markets must be competitive, if there is to be an effective rate-based or mass-based Federal Plan. At the heart of either approach are the assumptions that the agency will make about the likely upper-end cost of ERC or allowances.

IUG recommends that EPA consider identifying these cost assumptions and providing that a source could make a compliance payment to a State on a voluntary basis, rather than to achieve CO_2 emission reductions, which would otherwise be required of the source. Any such payment would be made to a State-administered fund that would be dedicated to promoting the reduction of CO_2 emissions. Further, such payment would need to be structured in a way to avoid interference with the "trading ready" status of a State.

EPA has offered a similar concept for consideration by the States, as they develop their own plans aimed at satisfying CPP requirements. At 80 Fed. Reg. 64,891, EPA offered the concept of a cost-containment reserve by stating:

> "Such state programs could include a number of different design elements. This includes broader program scope, where a program includes other emission sources beyond affected EGUs subject to CAA section 111(d) and new fossil fuel-fired EGUs, such as industrial sources. Programs might also include design elements that make allowances available in addition to the established emission budget. This includes project based offset allowances or credits from GHG emission reduction projects outsides the covered sector and *cost containment reserve* provisions that make additional allowances available at specified allowance prices." (emphasis added)

Beyond the concept of using any such fund to make additional allowances or ERCs available, we urge that such alternative compliance payment not be directly tied to either allowances or ERCs. Instead, by having the payments designed to promote CO_2 emission reductions, it would be reasonable to conclude that the payment, once made, is all that would be needed to comply.

Such an alternative compliance payment was used previously by the agency as part of the program to implement the ozone and particulate matter National Ambient Air Quality Standards. There, EPA allowed a source, facing costs higher than had been anticipated by EPA, to pay a set annual amount per ton to fund cost-effective emission reductions. See: Presidential Documents, "Memorandum of July 16, 1997, Implementation of Revised Air Quality Standards for Ozone and Particulate Matter," 62 Fed. Reg. 38,421 (July 8, 1997).

In establishing this compliance flexibility mechanism, EPA may wish to provide guidance to the States on how to establish their funds to assure that they achieve appropriate CO_2 emission reductions from EGUs. States, however, would control their respective funds and would have enough latitude to determine how the funds could be expended to best match the States' energy objectives, which could include investments in such areas as renewable energy, and energy efficiency, as well as carbon capture and geological storage.

The development of a default mechanism, such as a voluntary alternative compliance payment, would offer considerable assurance that sources would be able to comply with program mandates at reasonable costs and with the maximum degree of flexibility, while preserving reliability of energy supply.

8. **Federal Plan more stringent than proposed model trading rules**

In several ways, the proposed Federal Plan is more stringent, or provides fewer options, for States than do the proposed model trading rules. The additional stringency and limitations EPA places on options available under the proposed Federal Plan are unnecessary, and IUG objects to them.

EPA proposes that the Federal Plan restrict the categories of measures than can receive ERCs in comparison to the proposed rate-based model trading rule. The proposed Federal Plan would limit eligibility to generate ERCs to new any uprated renewable energy generation technologies, along with uprated nuclear generation. On the other hand, the proposed rate-

based model trading rule would allow renewable energy technologies, energy efficiency, qualified biomass, and industrial combined heat and power to generate ERCs.

Similarly, EPA proposes greater restrictions on the ability for renewable energy technologies to receive allowances under the Federal Plan than in the mass-based model trading rule. These, and any other such limitations and restrictions by EPA, are arbitrary and should be eliminated.

Therefore, IUG recommends that the proposed Federal Plan should not be more restrictive or provide fewer options than the proposed model trading rules, regardless of additional administrative costs to the EPA.

9. **Trading between rate-based and mass-based plans**

EPA expressed strong support for broad trading within the elements of the Clean Power Plan and the proposed Federal Plan. Indeed, we all recognize that a robust trading program is a key element to reduce the overall cost of the Clean Power Plan, including any Federal Plan that the agency may subsequently invoke.

IUG is concerned that, as proposed, EPA has stated that it will choose between the mass or rate-based programs in implementing the Federal Plan. We see this proposal as inviting unnecessary inefficiency and increased cost into a program that is already expensive enough.

Consider, for example, that a State opting for the rate-based approach could find itself with sources that actually emit significantly lower CO_2 emissions than could be the case had the same State chosen the mass-based approach. In such a case, we believe that a rate-based program should be allowed to treat the differences between authorized emissions under the two programs as allowances available for trading.

A more refined trading program that recognizes the benefits and value of both programs is a much better approach. We urge EPA to invite additional public comment on the merits of expanding its current trading proposals by considering how trading might occur between mass

and rate-based programs, so that the important goals of least-cost power and preservation of reliability be kept at the center of this rulemaking.

10. **Choosing between mass-based and rate-based approaches**

In the proposed Federal Plan, EPA has provided both mass-based and rate-based model trading rules. However, the agency proposed to choose only one kind of Federal Plan —mass-based or rate-based— for imposition on States that do not file a State plan that complies with the Clean Power Plan's mandates. At 80 Fed. Reg. 64,968, EPA states:

> "The EPA currently intends to finalize a single approach (i.e., either the mass-based or rate-based approach) for every state in which it promulgates a federal plan, given the benefits of a broad trading program, as discussed in the following section of this preamble."

However, the agency asks for comments about whether the agency should select either a rate-based or mass-based approach for the Federal Plan. IUG recommends that EPA not select one approach over the other. Indiana consumers —residential, commercial, and industrial— should have a reliable source of electricity that is generated at the lowest possible cost. We support preserving both a mass-based and rate-based approach to a Federal Plan, so that the critically important goals of low-cost electricity and a reliable electricity supply can be met. Further, the States should be the entities to determine which type of Federal Plan —mass-based or rate-based— should be imposed in order to promote the goals of low cost electricity and reliability.

Nevertheless, if EPA rejects this recommendation and pursues the course of selecting only one approach to a Federal Plan, IUG prefers a mass-based over a rate-based approach.

11. **Finalizing the Federal Plan**

EPA proposes to finalize one or both of the rate-based and mass-based model trading rules by the summer of 2016. However, the agency does not propose to finalize the Federal Plan rules at that time, stating:

> "The finalization of a model trading rule will not constitute a final action with respect to a federal plan for the affected EGUs in any state. Rather, the proposed federal plan will remain just that, a proposal. The EPA will promulgate a final federal plan for any state only after it has made a finding on a state's failure to submit a plan, or fully or partially disapproved a submitted state plan." *Id.* at 64,975.

EPA provides an additional nebulous and incomplete explanation of its intentions as follows:

> "The EPA is not providing specific regulatory text that would, if finalized, actually promulgate a federal plan for each state for which this proposed federal plan might be applied. We currently envision that this language would be in the form of a new section to the state-specific subparts of part 62 and would be ministerial in nature. It would likely provide that the affected EGUs in each such state are subject to a federal plan and would then cross-reference or incorporate by reference the substantive provisions of one of the two subparts proposed in this action (if finalized), along with any applicable modifications or adjustments as may be necessary, either based on new information or in response to comments regarding the application of the federal plan to that particular state." *Id.*

It appears, therefore, that EPA is proposing that owners and operators of EGUs in an affected State would become aware of the specific elements of the Federal Plan only when the agency finalizes it. Accordingly, EPA's proposal for finalizing a Federal Plan for an affected State, without public notice and an opportunity to comment, fails on at least three grounds.

First, in this rulemaking, EPA proposes to modify 40 C.F.R. § 60.27(c) without explaining the rationale for this change. 40 C.F.R. § 60.27(c) currently states, if a State does not submit an approvable plan, "The Administrator will, after consideration of any State hearing record, promptly prepare any publish <u>proposed</u> regulations setting forth a plan." (emphasis added.) However, EPA now proposes to amend 40 C.F.R. § 60.27(c) to state that "The Administrator shall promulgate a federal plan within 12 months after the date" the Administrator determines that a State has failed to submit an approvable State Plan.

Thus, the requirement of EPA first proposing a Federal Plan that would be imposed on an affected State has been eliminated without a substantive explanation, other than that the agency deems this to be a "slight modification" to 40 C.F.R. § 60.27(c). Such denial of public notice and an opportunity for comment on any regulation, and especially one with such sweeping implications, violates fundamental guarantees of due process.

Second, EPA's proposal to finalize a Federal Plan, without having first proposed it for public comment, is antithetical to the provisions of the Administrative Procedures Act (APA). The applicable section of the APA states, 5 U.S.C. § 553(b), as follows:

> (b) General notice of proposed rule making shall be published in the Federal Register, unless persons subject thereto are named and either personally served or otherwise have actual notice thereof in accordance with law. The notice shall include—
>
> (1) a statement of the time, place, and nature of public rule making proceedings;
>
> (2) reference to the legal authority under which the rule is proposed; and
>
> (3) either the terms or substance of the proposed rule or a description of the subjects and issues involved.

EPA claims that state-specific components of a final Federal Plan would be purely "ministerial," and the Federal Plan would otherwise simply reference applicable sections of the model trading rules. However, since EPA has asked for comments on hundreds of issues within the proposed Federal Plan, it would be impossible for the owners and operators of EGUs to have an adequate knowledge of the Federal Plan's components *until the Federal Plan is finalized* for that State. Such a construct flies in the face of the pillars of due process: notice and opportunity to be heard.

Third, § 307(d)(3) of the Clean Air Act contains even stronger requirements for notice and public comment, stating as follows:

> (3) In the case of any rule to which this subsection applies, notice of proposed rulemaking shall be published in the Federal Register,

> as provided under section 553(b) of title 5, shall be accompanied by a statement of its basis and purpose and shall specify the period available for public comment (hereinafter referred to as the "comment period"). The notice of proposed rulemaking shall also state the docket number, the location or locations of the docket, and the times it will be open to public inspection. The statement of basis and purpose shall include a summary of—
>
> (A) the factual data on which the proposed rule is based;
>
> (B) the methodology used in obtaining the data and in analyzing the data; and
>
> (C) the major legal interpretations and policy considerations underlying the proposed rule.

Without question, EPA's current proposal to impose a final Federal Plan on an affected state would fail mightily to meet the mandates of Clean Air Act § 307(d)(3), especially regarding notice of "the factual data on which the proposed rule is based" and the "methodology used in obtaining the data and in analyzing the data."

EPA's ill-conceived notion of finalizing a Federal Plan in this manner would ravage the well-established principles of due process. Providing comments on a generic Federal Plan will not substitute for public notice and the opportunity to comment on a state-specific Federal Plan, including EPA's finding of disapproval (or partial disapproval) of a State Plan. The proposed Federal Plan is fatally flawed in this regard.

12. **Conclusion**

IUG is one of many parties challenging EPA's Clean Power Plan in the U.S. Court of Appeals for the District of Columbia. A straightforward reading of the Clean Air Act illuminates the agency's overreach in promulgating the CPP. Additionally, EPA has acted in an arbitrary and capricious matter, particularly in ratcheting down the CO_2 emissions reductions mandated in the final CPP for States such as Indiana.

Similarly, EPA's proposed Federal Plan contains numerous, serious flaws that the agency must rectify, in case the Clean Power Plan survives federal court scrutiny. Accordingly, the Indiana Utility Group asserts that EPA must amend its proposed Federal Plan, as well as issue appropriate guidance to States and the power sector, as requested above.

##

November 25, 2014

The Honorable Gina McCarthy, Administrator
U.S. Environmental Protection Agency
1200 Pennsylvania Avenue, N.W.
Mail Code: 1101A
Washington, D.C. 204060

Air & Radiation Docket and Information Center
U.S. Environmental Protection Agency, Mail Code 28221T
1200 Pennsyvlania Ave, N.W.
Washington, D.C. 20460

Re: EPA-HQ-OAR-2013-0602

Comments on the Carbon Pollution Emissions Guidelines for Existing Stationary Sources: Electric utility Generating Units 79 Fed. Reg. 34830 (June 18, 2014)

Dear Administrator McCarthy:

The Indiana Energy Association (IEA) is an association of the Indiana investor-owned electric and gas utilities and a public trust gas utility, and the Indiana Utility Group (IUG) is a group comprised of rural electric cooperative and municipal joint action agency electric generating companies in Indiana that are not IEA members. Collectively, IEA/IUG deliver electricity and gas service to approximately 4,000,000 residents and businesses in Indiana. IEA/IUG is providing the attached comments to the Environmental Protection Agency (EPA) for the proposed **Carbon Pollution Emissions Guidelines for Existing Stationary Sources: Electric utility Generating Units; 79 Fed. Reg. 34830 (June 18, 2014).**

In summary, for the electric utility system in Indiana the Clean Power Plan (CPP) presents many challenges and inherent conflicts. Indiana's coal power plants operate efficiently today. Utilities have invested in their plants to maintain and enhance efficient operations. EPA's assumption that coal plants can improve efficiency (i.e., lower the heat rate) by 6% is unrealistic. Potential gains of 1% or perhaps 2% are far more realistic.

EPA is proposing to fundamentally change electric markets, moving from economic dispatch to environmental dispatch to lower carbon emissions. Forcing natural gas combined cycle plants to run at a 70% capacity factor will cause coal plants, which provide over 80% of Indiana's electricity today, to ramp up and ramp down more often, making them less efficient. This works against the previous operating efficiency goal.

Indiana has seen a large investment in renewable generation but the CPP does not give any credit for past actions and EPA does not acknowledge the costs of building, nor the time needed to acquire approvals or build, electric transmission lines to bring renewables to customers. Just as it has not acknowledged the significant natural gas and transmission line infrastructure investments associated with natural gas changes proposed in the rule.

Indiana has also moved forward recently with consideration of cost effective energy efficiency measures. EPA's proposal is based on flawed assumptions about Indiana's electricity sector. Our comments provide a more realistic appraisal of the potential for realizable energy savings in Indiana.

The IEA/IUG believes that the proposed CPP stretches EPA's legal authority well beyond applicable statutory provisions and precedent. The proposal also relies on unrealistic and unproven assumptions regarding heat rate, energy efficiency, natural gas and renewable energy. We are concerned that as the utilities that provide electricity for the state of Indiana that this rule intrudes on the effective management of the electricity system and which will impact the reliable and low cost manner in which we serve our customers. We strongly recommend that the rule be withdrawn and that the agency consider more streamlined and legally defensible alternatives.
We appreciate your consideration of these comments.

Sincerely,

Mark T. Maassel

Mark T. Maassel
President
Indiana Energy Association
On Behalf of the Indiana Utility Group

Indiana Utility Group Comments on EPA's Proposed Clean Power Plan

Introduction

The Indiana Utility Group ("IUG" or "Group") is comprised of the largest Indiana power providers, including investor-owned utilities, electric cooperatives, and municipal power companies. Together, the Group's members directly employ tens of thousands of people, pay hundreds of millions of dollars in taxes every year, and donate millions of dollars to local and national philanthropic causes. Their mission is to continue providing reliable service to Indiana electricity and gas customers at some of the lowest overall rates in the country.

These comments lay out the Group's major concerns and recommendations regarding the Environmental Protection Agency's ("EPA" or "Agency") proposed rule under Section 111(d) of the Clean Air Act: "Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units" (henceforth "the proposed rule"). The proposed rule is of particular importance to IUG because of the integral role coal-fired power plays in Indiana's energy generation mix. Coal-fired electric power plants provided 84 percent of Indiana's net electricity generation in 2013, according to the U.S. Energy Information Administration ("EIA").[1] Almost 14 percent of Indiana's existing coal-fired generating capacity will be retired or completely retrofitted by 2016 in anticipation of compliance deadlines associated with EPA's other environmental rules.[2] Because the proposed rule is designed to curtail the use of those facilities either directly or indirectly via statewide mandates, the IUG is concerned that EPA's proposed rule could have far-reaching implications for Indiana's energy future.

Affordable and reliable electric power is essential to the continued recovery of Indiana's manufacturing economy, which accounts for about 500,000 high-paying jobs in the State.[3] The coal industry employs another 28,000 Hoosiers.[4]

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[1] "Indiana: State Profile and Energy Estimates." U.S. Energy Information Administration. Updated March 27, 2014.
[2] "Coal Unit Shutdowns." American Coalition for Clean Coal Electricity. July 28, 2014.
[3] "Indiana Manufacturing Facts." National Association of Manufacturers. 2014.
[4] "Mike Pence: EPA's anti-coal plan will devastate Indiana economy." *Indy Star*. June 6, 2014.

EPA admits this rule would fundamentally impact every aspect of the U.S. electricity sector if it takes effect; the Agency's own estimates show the proposed rule increasing average nationwide retail electricity prices "roughly 6 to 7 percent in 2020 relative to the base case."[5] Indiana will experience a disproportionate share of these rate hikes, not just because the state is so reliant on coal for its electricity, but also because Indiana has average retail electricity prices below the national average. In fact, analysis by NERA Economic Consulting suggests the actual increase in rates for Indiana could be closer to 12 percent.[6] With 1.3 million lower- and middle-income households in Indiana, spending an average of 19 percent of their after-tax income on energy, our State is uniquely vulnerable to these rate hikes.[7]

The proposed rule is structured as follows: Each state must reduce its total carbon emissions to reach a target statewide emission rate by 2030. The final target for Indiana is 1531 lbs/megawatt hour ("MWh"). The rule also imposes an interim target of 1607 lbs/MWh for the period 2020-2029.[8] To achieve compliance with these targets, EPA proposes that states consider four "Building Blocks," which together the Agency contends comprise the "Best System of Emissions Reduction" ("BSER"). EPA uses what they believe to be the aggregate potential impact of these Building Blocks as the basis for the interim and final state emissions targets. The Building Blocks are:

1 – improving the heat rate at all existing coal-fired power plants by an average of 6 percent;

2 – increasing the dispatch of natural gas combined cycle ("NGCC") plants to an average of 70 percent capacity;

[5] See Proposed Rule, at page 34934.
[6] "Potential Energy Impacts of the EPA Proposed Clean Power Plan." NERA Economic Consulting. October 2014.
[7] "Energy Cost Impacts on Indiana Families." American Coalition for Clean Coal Electricity. December 2013.
[8] See Proposed Rule, at page 34895.

3 – maintaining existing nuclear plants in conjunction with the construction and use of renewable energy generating facilities; and

4 – implementing end-use energy efficiency measures to reduce electricity demand in the state.

The proposed rule requires that each state submit a 111(d) Plan that specifies how it will meet its unique emission rate target using these four Building Blocks or any other measures that it may choose.

Legality

There are questions as to whether EPA can use Section 111 of the Clean Air Act ("CAA") to regulate carbon emissions from existing power plants, given that these plants are already regulated under Section 112. Section 111(d)(1)(A)(i) of the CAA stipulates that EPA cannot regulate a "source category" which is already regulated under Section 112. When EPA completed the Mercury and Air Toxics Standards ("MATS"), rules which have had and will continue to have a significant impact on Indiana, the agency foreclosed the possibility of dual-regulation under Section 111(d). Quite simply, the only legal authority the agency has offered in support of the proposed rule has already been rendered null and void by the requirements of the statute. This question is currently being heard by the U.S. Court of Appeals for the D.C. Circuit.[9]

Putting this issue aside, and assuming that EPA may use Section 111 to regulate carbon emissions from existing power plants, the proposed rule goes well beyond EPA's statutory authority under Section 111. EPA simply does not have authority under the CAA (or any other statute) to impose a statewide CO_2 emission reduction requirement. Under Section 111(d) of the CAA, EPA may require states to establish "standards of performance" for "any existing source" within their borders. The statute defines a "standard of performance" to mean: "A standard for emissions of air pollutants which reflects the degree of emission limitation achievable through the application of the best system of

[9] Murray Energy Corporation v. U.S. Environmental Protection Agency, U.S. Court of Appeals for the D.C. Circuit, No. 14-1112.

emission reduction..."[10] EPA has always interpreted the "best system of emissions reduction" as something that occurs at the "source," e.g. the existing coal-fired power plant. However, in the proposed rule the agency has taken the novel position that because coal-fired power plants are themselves elements of the broader system that is the entire U.S. electricity sector, it is to this broader system that the best system of emissions reduction is to be applied.

There is no limit to this unprecedented and expansive reading of the statute, which is why, for example, the agency is able to justify end-use energy efficiency requirements using the logic that energy efficiency saves electricity that comes from the source. In summation, the statute and almost 40 years of regulatory history make it clear that a standard of performance is a requirement that applies to individual plants based on the best system of emission reduction that can be applied to those plants to achieve a "continuous emission reduction."

Thus, Building Blocks 2, 3, and 4 may not be used to set a "standard of performance" within the meaning of the CAA. Building Block 2 is based on dispatch decisions that are outside the control of "any existing source," which is the only entity that can be regulated under Section 111(d). Those same dispatch decisions are outside the control of any federal or state environmental agency, which are the only entities that may regulate a source. Building Block 3 directly pertains to new investment decisions that are entirely unrelated to the operation of "any existing source." Finally, Building Block 4 directly pertains to the behavior of electricity consumers, which is clearly outside the control of utilities and has nothing to do with "any existing source."

In any event, Section 111(d) clearly does not give EPA authority to set an emission rate that applies to replacement generation and customer electricity usage. It only gives EPA authority to require states to set standards of performance that apply to individual power plants within the regulated source category.

[10] 42 U.S.C. § 7411(a)(1)

EPA's proposed rule relies heavily upon computer modeling, but many of the key assumptions used throughout the modeling process have not been made available for public comment. EPA's refusal to disclose its modeling assumptions and the full suite of model outputs renders regulations based on those models arbitrary and capricious. EPA failed to include key assumptions it used when modeling the effects of 111(d) in the record. The agency continues to refuse outside requests for the relevant information. Without access to the assumptions used to formulate the rule and the full portfolio of model outputs, stakeholders cannot confirm or deny the veracity of the Agency's claims about the feasibility of compliance.

Making State 111(d) Plans "enforceable" could require major changes in Indiana law, given Building Blocks 2, 3, and 4. Indiana has not authorized the Indiana Utility Regulatory Commission ("IURC") to mandate specific dispatch decisions, implement renewable portfolio standards, or require end-use energy efficiency measures. IURC also lacks the authority to directly regulate some electricity markets in Indiana, like those operated by municipal utility districts and rural electrical membership cooperatives or corporations ("REMCs"). In fact, Indiana explicitly gives municipalities and REMCs the option to opt out of IURC oversight. Yet these entities and their generating assets are covered by the proposed rule.

Section 111(d) also provides that in cases where a state fails to submit a satisfactory 111(d) Plan the "Administrator shall have the same authority to prescribe a plan for a state…and to enforce the provisions of such a plan."[11] Thus, under certain circumstances, the proposed rule would require EPA to enact a Federal 111(d) Plan of questionable legality. Given the timeframes involved, it is certain that some states – perhaps most states – will not be able to submit satisfactory 111(d) plans by the proposed deadline. In this case, EPA has said that it would impose a Federal 111(d) Plan on any such state based on the same four Building Blocks that have been suggested for use in the state plans. But EPA simply

[11] 42 U.S. Code § 7411(d)(2)

does not have authority or the expertise to enact the measures assumed by Building Blocks 2, 3, and 4. If EPA attempted to undertake requirements such as mandating non-economic dispatch or imposing a renewable portfolio standard, it would severely infringe on the regulatory jurisdiction of the states.

The CAA stipulates that EPA must issue rules for new sources as a prerequisite to finalizing rules for existing sources under Section 111(d). To satisfy this requirement, EPA is relying upon the agency's rule for modified and reconstructed sources. While the CAA treats "modified or reconstructed" sources as "new," there is no precedent or legislative history for using a modified and reconstructed source rulemaking (in the absence of a rulemaking for actual new sources) as a basis for proceeding to a rule for existing sources. Setting aside the lack of precedent, EPA's innovative use of the rule for modified & reconstructed sources to justify the proposed rule is also based on an incorrect reading of the statute. Section 111(d) establishes standards of performance for existing sources "to which a standard of performance under this section would apply if such existing source were a new source."[12] The test is whether existing sources would be covered by Section 111(b), were they new. The answer is no, and will remain no until a New Source Performance Standard is finalized for sources affected by the proposed rule. The rule for modified and reconstructed sources does not regulate the category of new sources, it only covers a subset. Therefore, EPA's proposed rule for modified and reconstructed sources will not satisfy the requirements of the CAA.

Administrative Process Concerns

Some, but not all, critical documents were added after the proposed rule was published in the Federal Register. For instance, EPA released two new years of data on electricity consumption on October 28th. This new data forced stakeholders to re-do their computations just one month before the end of the comment period. Furthermore, EPA has done computer modeling to support its proposed rule but has not made the key details of these modeling runs available for public comment. Critical

[12] 42 U.S. Code § 7411(d)(1)(A)(ii)

modeling runs that bear upon the economic, consumer, and energy impacts on Indiana remain unavailable.

The agency has not had a robust dialogue regarding reliability issues with the Federal Energy Regulatory Commission ("FERC"), regional reliability organizations, or state commissions. The potential implications of changing the energy model from economic to environmental dispatch are significant and wide-reaching. Despite the substantial reliance of the Upper Midwest on coal-powered generation, EPA conducted no public hearings in the region regarding the proposed rule.

EPA has not provided sufficient guidance on how to calculate a mass-based emissions target. On November 6, only three weeks before the deadline for submitting comments, the agency released a technical support document on this question. That is clearly not enough time to assess the merits of EPA's methodology in an Indiana-specific context. Furthermore, the rate-to-mass information provided still relies on the fanciful notion that Indiana's electricity demand will not increase between now and 2030. Were the state to adopt a mass-based emissions target, Indiana would be placing a hard cap on future electricity demand regardless of economic growth and population growth without any mechanism for enforcing that cap. The agency's proposed methodology for states to calculate their own figures depends on a host of economic assumptions about future demand, power plant lifetimes, the actions of other states, and future natural gas prices, among other important modeling inputs.

Timing Issues

EPA has provided inadequate time for the states to submit their 111(d) Plans. EPA intends to finalize its 111(d) Rule in June 2015. Absent an extension, states must submit their 111(d) Plan by June 2016. The Indiana General Assembly meets in 2016 from the second week of January to March 15. This does not allow the Indiana Department of Environmental Management ("IDEM") sufficient time to develop a plan and the legislature sufficient time to make required changes to state authorities. In

effect, EPA has left Indiana in a position where Indiana has to reorganize its electricity sector in a matter of months.

EPA's decision to enforce "interim targets" requires states to demonstrate specific and verifiable emissions reductions every year between 2020-2029, before the final compliance date of 2030. For states that have a long way to go before they reach EPA's expected "rate of progress," these interim targets would require that a substantial percentage of the total expected emission curtailment occur before 2020. For Indiana, EPA's proposed interim target accounts for approximately 80 percent of the total emissions curtailment the agency expects from our state. This is simply not feasible.

EPA has entertained the possibility that it may need to adjust the interim goals and/or final targets for some states. However, EPA officials have suggested that any petition for an adjustment has to take place during the comment period. That expectation places a heavy burden on states to fully evaluate a number of very complex issues in just four months – well before they have a chance to craft a 111(d) Plan, gather data, or run into potential problems during the implementation process.

Should Indiana fail to submit a 111(d) Plan, EPA will promulgate a Federal 111(d) Plan. Questions of legality aside, EPA is ill-equipped to make the specific technical decisions about Indiana's power sector that such a Plan would require. EPA has no experience overseeing reliability, conducting local cost analysis, or verifying demand response. These functions are only the most basic of the many responsibilities that a Federal 111(d) Plan would entail. As Governor Pence put it in a letter with 14 other governors earlier this year, "we are left to assume that EPA is entertaining the possibility of overreaching its authority."[13]

Compliance Issues: Building Block 1 – Heat Rate

Building Block 1 of EPA's "Best System of Emission Reduction" is for coal-fired electric generating units ("EGUs") to improve their heat rate, "thereby reducing the amount of fuel needed to

[13] Letter to President Barack Obama signed by 15 governors. September 9, 2014. http://governor.alabama.gov/assets/2014/09/RGA-Letter-to-POTUS.pdf.

produce the same amount of electricity and lowering the amount of CO_2 produced as a byproduct of fuel combustion."[14] EPA asserts that coal-fired EGUs can improve their operating efficiency in two ways. First, unit operators can improve their efficiency via the adoption of "best practices." Second, plant owners can implement "equipment upgrades." To support the agency's technical analysis, EPA cites a 2009 study by the engineering firm Sargent & Lundy. EPA asserts, "the total of the estimated potential heat rate improvements from adoption of best practices to reduce heat rate variability and implementation of equipment upgrades…is six percent."[15] For a number of reasons, IUG believes EPA's 6 percent figure is unrealistic and inappropriate for coal-fired steam EGUs in Indiana.

EPA expects the adoption of best practices to yield an average 4 percent improvement in heat rate. This number is overly ambitious; utilities already have a significant financial incentive to locate and eliminate inefficiencies in their operations. Any inefficiency resulting from suboptimal operating practices represents a potential financial loss for the plant owner. Thus, many Indiana plant operators have already implemented what they believe to be the best practices. EPA argue that "[h]eat rate improvements yield important benefits to affected sources by reducing their fuel costs."[16] IUG agrees with this characterization, and it is for precisely this reason that mandating additional heat rate improvements merely reinforces an existing incentive structure. The idea that Indiana utilities are deliberately overlooking potential improvements in their operations in the status quo is unsubstantiated and counter-intuitive. Yet, it is precisely this assumption upon which EPA's proposal for large improvements relies.

EPA expects the additional 2 percent improvement in heat rate to come from equipment upgrades, selected from a list provided by the aforementioned Sargent & Lundy study. The agency

[14] See Proposed Rule, at page 34859.
[15] See Proposed Rule, at page 34861.
[16] See Proposed Rule, at page 34859.

rightly recognizes that "some EGUs may have already implemented some of these upgrades."[17] However, the proposed rule assumes without justification that roughly half of the equipment upgrades in question remain and are thus realizable at EGUs across the country. EPA presents no data to support this assertion. Furthermore, the equipment profile of coal-fired EGUs in Indiana may vary substantially from that of the average U.S. unit. EPA has yet to conduct any subnational analysis of the potential for plant upgrades. As such, the 2 percent improvement in heat rate Indiana plant operators are supposed to achieve at their coal-fired units is unsubstantiated and should be reconsidered. Instead, EPA should conduct a plant-specific analysis at each existing source to render an appraisal of potential improvements that is more sensitive to real present-day circumstances in Indiana.

There are additional problems with EPA's methodology for calculating heat rate improvements from equipment upgrades that IUG believes need to rectified in the proposed rule. First, EPA's 2 percent target for gains from equipment upgrades does not assume degradation, which results in year-over-year reductions in efficiency. As soon as new equipment is installed, its ability to improve the operational performance of the unit starts to decline. Yet, EPA assumes improvements from equipment upgrades will remain constant into perpetuity. If an EGU owner wanted to address the degradation in equipment, additional costs, above those assumed by EPA in the proposed rule, would be incurred by the owner to attempt to maintain heat rate improvements. Second, EPA assumes the gains from equipment upgrades are additive, when some of the recommended retrofits obviate other possible improvements (e.g. installing a new turbine vs. retrofitting the seals on an older turbine).

IUG is concerned about the lack of discussion afforded "parasitic load" in the proposed rule. Parasitic load is the amount of electricity consumed by EGU components, including pollution-control equipment mandated by other EPA environmental regulations. These regulations, which include, among others, Mercury and Air Toxics Standards ("MATS"), National Ambient Air Quality Standards ("NAAQS"),

[17] See Proposed Rule, at page 34860.

and Section 316(b) of the Clean Water Act ("CWA"), mandate that coal-fired units install equipment that may increase current parasitic load and thus reduce the efficiency of a power plant. In regard to this concern, EPA asserts: "Like gross heat rate, parasitic load can be addressed both through adoption of best practices and through equipment upgrades…"[18] It seems the agency believes concerns about parasitic load are limited to the effects of the proposed rule, when, in fact, the primary concern is the interaction between the proposed rule and existing environmental regulations. Because the denominator for the unit of measure EPA uses to assess heat rate is net MWh, rather than the traditionally used gross MWh, the addition of pollution controls needed to comply with other EPA regulations were not considered when EPA established their emissions targets. These regulations will result in an increase in the CO_2 rate (lb/Net MWh) without increasing the actual CO_2 mass emission from the source. In effect, power producers are being asked to recover the heat rate lost from other EPA rules before they start counting efficiency gains towards the average 6 percent heat rate improvement. The proposed rule states: "We have therefore not included any separate estimate of parasitic load reductions achievable through best practices in our goal-setting data inputs."[19] By disregarding potential reductions in parasitic load that may result from the proposed rule, EPA also disregards expected future increases in parasitic load resulting from existing and expected new EPA regulations. IUG believes the greater potential is for net increases in parasitic load.

IUG recommends work practice standards that are periodically reviewed and implemented on a source specific basis. If EPA does pursue a uniform heat rate standard, the agency should exclude emissions released during periods of unit startup and shutdown. In fact, EPA has recognized this type of exclusion for other environmental regulations.[20] Not only would this approach help ameliorate some of the complications outlined above, it would also prevent multiple environmental regulations from

[18] See Proposed Rule, at page 34860.
[19] See Proposed Rule, at page 34860.
[20] "Policy on Excess Emissions During Startup, Shutdown, Maintenance, and Malfunctions." U.S. EPA. February 15, 1983. http://www.epa.gov/region7/air/nsr/nsrmemos/ssm.pdf.

potentially working at odds to one another. Given that EPA believes the proposed rule is "consistent with the long-term planning and investment processes already used in [the electricity] sector," taking into account other environmental regulations seems paramount to promulgating a rule consistent with the aims of the CAA.[21]

EPA did not evaluate the feasibility of achieving the heat rate improvements called for under Building Block 1 in conjunction with the changes to dispatch called for under Building Block 2. IUG believes increasing the dispatch of natural gas combined cycle plants to 70 percent of capacity will change the way that existing coal-fired units are dispatched such that the overall performance would be significantly less efficient. Coal-fired plants are at their most efficient when they are running at or near 100 percent capacity. If transmission operators re-prioritize the dispatch of natural gas, that would likely force coal-fired plants to operate at a lower output factor assuming that the assumptions from Building Blocks 3 and 4 are realized as EPA has envisioned. Running plants at a lower output factor will result in a lower overall capacity factor for coal-fired plants, which causes a de facto net heat loss.

When coal-fired plants assume a reduced operating profile, a number of problems arise that make EPA's targets for Building Block 1 even harder to achieve. First, running coal-fired plants at a lower capacity factor increases the need for more start-up and shut-down operations. The end result is additional heat loss, because coal-fired plants operate inefficiently during these processes. Second, start-up and shut-down procedures consume auxiliary power, which results in additional reported emissions and heat loss. During this period, the plant may in fact produce no net generation. EPA's calculations do not assume auxiliary power loss or the possibility of a lower output factor as a result of the proposed rule. As a result, plant operators are being asked to make up for several percentage points of lost efficiency before they can start counting improvements towards the net gain of 6 percent.

[21] See Proposed Rule, at page 34832.

EPA should adjust the average expected heat rate improvement based on the interplay of all of the Building Block assumptions. IUG is concerned that each utility will have to evaluate whether it is prudent to invest monies to improve heat rate knowing that dispatch will be curtailed. The end result could be the premature shutdown of coal-fired plants in Indiana in excess of EPA's estimates, given that the agency did not take some of the aforementioned problems into consideration in its modeling efforts.

The Sargent and Lundy study on heat rate improvements was meant to "provide valuable information for comparative purposes when evaluating the advantages and disadvantages of various concepts," not to establish a roadmap for regulatory requirements applied to all coal-fired EGUs.[22] A 2014 study by the Nicholas Institute for Environmental Policy Solutions notes, "Sargent and Lundy's report only estimates potential improvements and does not list unit by unit efficiency gains and costs. To date, there has been no comprehensive analysis of the actual opportunities that exist for efficiency improvements."[23] Furthermore, a 2014 clarification letter sent by engineers at Sargent and Lundy to the National Rural Electric Cooperative Association ("NRECA") says "Sargent & Lundy's 2009 report does not conclude that any individual coal-fired EGU or any aggregation of coal-fired EGUs can achieve 6% or any broad target, as estimated by the EPA." In short, EPA's numbers are not only unrealistic, they also lack academic support.

Compliance Issues: Building Block 2 – Dispatch of Natural Gas at 70 percent

Building Block 2 of EPA's "Best System of Emissions Reduction" assumes transmission operators increase the dispatch of NGCC plants to 70 percent of capacity. The proposed rule applies to NGCC plants that "were in operation or had commenced construction as of January 8, 2014."[24] Uncertainties exist regarding what, if any, regulatory agency would have the authority to enforce a minimum

[22] "Coal-Fired Power Plant Heat Rate Reductions." Sargent & Lundy. January 22, 2009.
[23] "Heat Rate Reductions and Carbon Emissions." Nicholas Institute for Environmental Policy Solutions. April 22, 2014.
[24] See Proposed Rule, at page 34862.

utilization limit, or to design a permitting condition for specific sources. Because transmission operators employ "security-constrained economic dispatch," environmental considerations do not directly factor into dispatch decisions.[25] Instead, existing environmental regulations have had an indirect impact on dispatch decisions by altering the variable cost of electricity produced at EGUs. In this regulatory and policy context, EPA proposes two ways for states to implement Building Block 2. First, states can superimpose a de-facto price on carbon through a variety of market-based mechanisms, which would increase the variable cost of dispatching higher-emitting EGUs. Second, states can "impose limits on utilization or CO_2 emissions at higher-emitting EGUs."[26] IUG believes placing direct limits on plants' operating conditions entails significant legal and practical difficulties for Indiana.

Directly limiting the number of hours a coal-fired plant can operate puts a hard ceiling on the amount of electricity the plant can provide to the grid. In periods of unusually high demand, Indiana's coal-fired plants may be necessary to preserve the state's bulk power reliability. Extreme weather conditions provide a case in point, because extreme weather causes demand to skyrocket at the same time that natural gas supplies face unanticipated constraints. During the early 2014 cold spell known as the "polar vortex," the vast majority of coal-fired units that were slated for retirement because of EPA's MATS were up and running at full capacity, providing critical electricity supplies to residential customers. To the extent that displacing coal-fired units with NGCC units causes the former to adopt a reduced operating profile, Building Block 2 could leave utilities without the tools needed to respond to extreme conditions.

EPA's suggestion that states employ market-based mechanisms to alter the cost of dispatch at higher-emitting units is also problematic. It is unclear based on the text of the proposed rule whether the power plant operator or MISO would be responsible for establishing compliance with Building Block 2 for the purposes of enforcement. It is also unclear what the legal implications would be if, for example,

[25] See Proposed Rule, at page 34862.
[26] See Proposed Rule, at page 34862.

Indiana included a carbon price in its 111(d) Plan, EPA approved that Plan, and then Indiana's NGCC plants operated at an average capacity factor of less than 70 percent in any given year. The notion that a pricing or permitting scheme can be reliably correlated with a specific operating threshold at EGUs lacks empirical support. Accomplishing such a task would require accurate long-term forecasts about the future trajectory of electricity use decades into the future, something even the federal government admits is beyond its capabilities.[27]

If EPA's proposed rule puts the reliability of Indiana's electricity supply at risk, IUG's members will be confronted with significant legal difficulties, including potential exposure to legal liability. Once EPA approves Indiana's 111(d) Plan, the Plan will be federally enforceable. At that point, plant owners and operators will be liable under the CAA for failing to operate in accordance with the terms of Indiana's Plan. However, the Federal Power Act ("FPA") empowers the Secretary of Energy and FERC to order power plants to operate if doing so is necessary to preserve bulk power reliability.[28] Were the Secretary of Energy or FERC to order an IUG member to operate a plant in a manner that violates Indiana's 111(d) Plan, that company would be put in the unenviable position of either violating 111(d) and opening itself up to penalties, or putting the reliability of the grid at risk and risking an enforcement action. Eventually, the courts will have to decide, but not before consumers of electricity and power providers bear the costs of all this legal confusion.

Given the aforementioned failure by EPA to consult with FERC or other entities charged with maintaining bulk power reliability in the process of writing the proposed rule, EPA should exclude Building Block 2 from consideration until the agency is able to address these concerns. So far, the agency has come up short, as evidenced by the North American Electrical Reliability Corporation's ("NERC") statement that "Essential Reliability Services may be strained by the proposed CPP."[29] MISO's

[27] "Annual Energy Outlook 2014." U.S. Energy Information Administration. April 2014.
[28] See 16 U.S.C. § 824a(c) and 16 U.S.C. § 824f.
[29] "Potential Reliability Impacts of EPA's Proposed Clean Power Plan." NERC. November 2014.

preliminary assessment of the reliability implications associated with the proposed rule projected that roughly 26 percent of Indiana's coal units would be retired, resulting in "significant reliability violations."[30]

IUG believes there are significant unanswered questions associated with EPA's expectations for natural gas dispatch. For instance, it is unclear based on EPA's analysis that an annual utilization rate of 70 percent or higher is realistic for all NGCC plants. Only 10 percent of existing U.S. NGCC plants operated at an annual utilization rate of 70 percent or higher in 2012.[31] According to EPA, the average capacity factor of the U.S. NGCC fleet in 2012 was between 44 and 46 percent.[32] Indiana's NGCC plants operated at a slightly higher capacity that year, with a statewide average of 53 percent.[33] While it is true that some plants exceeded a 70 percent average in 2012, EPA has done no analysis to suggest that a similar operational profile is universally replicable or sustainable. Different NGCC plants may operate different equipment and service different demand profiles; EPA's uniform treatment of capacity elides these important distinctions. When EPA assumes all existing plants can achieve its "best system" standard, the agency conflates technical capability with operational feasibility.

The use of 2012 as the baseline year for estimating the feasibility of increased dispatch may be problematic. 2012 was an anomalous year in natural gas markets. Mild weather led to large declines in residential and commercial gas consumption as well as electricity demand. For this and other reasons, natural gas prices fell below coal prices. This price decline led to increased dispatch from NGCC plants, relative to coal-fired plants. Since 2012, coal-fired plants have, for the most part, regained their market share in electricity markets. This effect is particularly noticeable in Indiana. A report by SNL Energy projects that gas generation's share of Indiana's electricity mix will decline from 13.6 percent in 2012 to

[30] "Transmission Reliability Impacts due to the proposed EPA regulations: A Preliminary Assessment." MISO. November 12, 2014.
[31] "GHG Abatement Measures." EPA Technical Support Document. At page 3-9.
[32] "GHG Abatement Measures." EPA Technical Support Document. At page 3-6.
[33] "Data File: Goal Computation - Appendix 1 and 2." EPA Technical Support Document.

5.3 percent in 2030.[34] EPA's computations assume that the state of affairs that existed in 2012 persists today, when data and market trends suggest that is not the case. EPA should re-formulate its estimates for realistic NGCC utilization on the basis of a more representative multi-year average.

Increasing the dispatch of electricity produced at NGCC plants involves significant gas pipeline and electricity transmission issues. Most coal-fired power plants in Indiana are not sited side-by-side with their natural gas-fired counterparts; there is no guarantee NGCC units could send their power to the same loads currently being serviced by coal-fired units. The longer the distance between the natural gas-fired plant and the market it serves, the higher the "line loss" associated with delivering the electricity to market. Line loss cuts into the emissions savings EPA expects to result from gas-dispatch. EPA includes line loss calculations in the agency's feasibility estimates, but those numbers are not Indiana-specific. EPA should recalculate its estimates for line loss using state-specific data. Congestion is also a major concern, between and within transmission regions. PJM in particular has experienced major congestion issues in the transmission of electricity between its eastern and western markets.[35] Thus, there is no guarantee Indiana will be able to economically consume the excess electricity produced by NGCC plants operating at a higher capacity factor.

EPA assumes that necessary gas pipeline infrastructure can be added in time to support reliable operation of gas units at higher capacity factors, but did no analysis of the current supply constraints for existing NGCC units. Many units operate with interruptible contracts for gas supply that may not support increased operation during peak demand periods, particularly in the winter when units compete with home heating for available supplies of natural gas. Recently, officials at the Southwest Power Pool have

[34] "Most states need more cuts to meet proposed CO2 rule: SNL Energy." SNL Energy. June 28, 2014. http://www.mining.com/web/most-states-need-more-cuts-to-meet-proposed-co2-rule-snl-energy/.
[35] "2014 Market Efficiency Analysis." PJM Transmission Expansion Advisory Committee Meeting. June 5, 2014. http://www.pjm.com/~/media/committees-groups/committees/teac/20140605/20140605-market-efficiency-update.ashx.

noted that major new transmission projects can take up to 8½ years.[36] EPA made allowances in the computation of state goals for shortfalls in fossil fuel supplies, but only for states where the sum of coal, oil, and natural gas resources fell short of the natural gas required to sustain a 70 percent capacity factor at existing NGCC plants.[37] Obviously coal, oil, and natural gas are dis-analogous for the purpose of estimating resource availability, insofar as a state may possess large supplies of one and very limited supplies of another. For instance, Indiana produced 826.8 trillion Btus of coal in 2012, but only 8.9 trillion Btus of natural gas that year. EPA should re-formulate its analysis of natural gas availability to account for potential supply constraints in Indiana, and EPA should include in its analysis a robust model of the effect a nationwide increase in the demand for natural gas will have on pipeline capacity in the short-term.

The proposed rule will greatly increase demand for natural gas, creating upward pressure on prices and operating costs. EPA's modeling shows spot prices increasing "by an average of no more than ten percent over the 2020-2029 period."[38] This projected increase in gas prices is a major contributor to the increase in wholesale electricity prices EPA and others anticipate taking place as a result of the proposed rule. A study by the State Utility Forecasting Group at Purdue University ("SUFG") discusses the impact increased natural gas prices could have on consumers in Indiana:[39]

> From the customer perspective, the commodity price accounts for approximately 62 percent of the average residential bill in Indiana, with the remainder stemming from costs associated with the distribution system and trackers. Since the cost of procuring the natural gas in the open market is passed directly to the customer in the captive market with no profit to the utility, there is a direct dollar for dollar impact of changes in natural gas prices to changes in a customer's bill. Thus, if natural gas prices increase (or decrease) by $1/mmBtu, a customer's bill will increase (decrease) by $1 for every mmBtu of natural gas consumed. To put this in perspective, consider a customer who

[36] "Grid operator urges EPA to delay carbon plan implementation by 5 years." *E&E Energywire*. October 10, 2014.
[37] "Goal Computation Technical Support Document." U.S. EPA. June, 2014. At page 11.
[38] See Proposed Rule, at page 34865.
[39] "Natural Gas Market Study." State Utility Forecasting Group. November 2013. http://www.in.gov/iurc/files/Natural_Gas_Market_Study.pdf.

> consumes 200 therms in a month (10 therms equal one mmBtu). For every $1/mmBtu change in the natural gas price, the customer's bill will change by $20.

EPA "view[s] these projected impacts as not unreasonable" because the price increases in question are "well within the range of historical natural gas price variability."[40] The fact that harmful increases in the wholesale price of natural gas have occurred before is of little comfort to the Indiana consumers who will bear the brunt of EPA's proposed rule. EPA should conduct a thorough analysis of the proposed rule's impact on natural gas prices in Indiana and the effects that will have on Indiana consumers and the state's economy.

If Indiana elects to impose direct limits on the operating profile of higher-emitting EGUs, EPA expects NGCC plants to fill the gap. That could be problematic for Indiana's integrated gasification combined cycle ("IGCC") units, which were specifically excluded from EPA's calculations for Building Blocks 1 and 2. Emissions of CO_2 at IGCC plants are in line with coal-fired power plants; however, heat rate improvements are not viable due to the intrinsic nature of the process. Therefore, it appears that in order for a coal-heavy state such as Indiana to meet EPA's goals, IGCC plants will be dispatched less frequently than would otherwise be the case. IUG is concerned its members' existing investment in IGCC plants will be effectively penalized by the proposed rule. EPA should re-formulate its calculations for Building Block 2 to directly address the relationship between re-dispatch and IGCC plants in a way that takes into account those plants' unique attributes.

Mandating specific unit dispatch decisions on a state-by-state basis presents significant "seam issues" for states like Indiana, where multiple regional transmissions organizations ("RTOs") manage the dispatch of electricity units located in different parts of the state. A PJM report on capacity imports and exports to and from the Midcontinent Independent System Operator, Inc. ("MISO") explains that "reliability requires the capacity construct and system planning to be consistent with actual grid

[40] See Proposed Rule, at page 34865.

operations."[41] The dispatch decisions required by Building Block 2 are precisely the sorts of planning changes that will make efficient seam coordination increasingly difficult. EPA should conduct an analysis of the interactions between Building Block 2 and the PJM-MISO seam and incorporate those findings into the structure of the final rule.

IUG believes Building Block 3 may run counter to maintaining a high utilization rate at natural gas plants. Renewable energy suffers from intermittent generating capacity, as a result of near-constant variation in sunlight and wind availability. In order to maintain grid reliability, natural gas plants are needed on standby to fill-in for tapering renewable energy generation. If all natural gas plants are instructed to maintain a high utilization rate, there may be insufficient spare capacity to fill-in for intermittent renewables. As a result, EPA is incorrect to assume that the emissions reductions that would occur as a result of Building Blocks 2 and 3 are additive. Rather, the two numbers overlap to a significant extent. EPA should adjust Indiana's state emissions targets accordingly.

EPA has yet to clarify whether new NGCC plants will count towards the baseline for compliance with the proposed rule. Section 111(d) of the CAA refers to existing sources. However, modified and reconstructed sources are treated as "new" sources in the CAA. Therefore, there is currently a lack of clarity about the credit Indiana can receive for converting coal-fired power plants to natural gas-fired plants, or the credit Indiana can receive for any other sort of plant modification or reconstruction. EPA should be clear about Indiana's options in this regard. EPA should be consistent in its application of the term "modified & reconstructed" to gas plants, as it relates to the proposed rule.

Specifically, EPA should allow new NGCC plants subject to regulation under CAA section 111(b) to function as compliance sources under the proposed rule. To accomplish this, EPA should specifically include new NGCC plants as an "affected entity," as that term is defined in §60.5820 and used in

[41] "PJM/MISO Seams Coordination and Capacity Deliverability." Presentation by PJM at FERC Meeting. June 20, 2013. http://www.ferc.gov/industries/electric/indus-act/rto/pjm.pdf.

§60.5780 of the proposed rule.[42] This would allow states to use new NGCC plants as a compliance mechanism both for affected EGUs (by allowing the substitution of CO_2 emission rates from retired or lesser-utilized coal-fired EGUs with lower rates from new NGCC capacity) and to meet or maintain state emission rate goals if additional capacity is need for future demand.

Unless all states are permitted the option of accounting for new NGCC plant in their 111(d) Plans, the present exemption practically ensures that newly constructed NGCC plants will have little to no impact on state average CO_2 emission rates. Because many states are likely to adopt a rate-based approach, and most NGCC units will not be constructed until after the proposed rule is finalized, the majority of new NGCC plant will not be a factor towards achieving compliance with the proposed rule. That is an absurd result. Indiana should have the option of determining if or how to consider new NGCC plants in its 111(d) Plan.

A simple example demonstrates the challenge of incentivizing new NGCC plants in states with rate-based compliance goals. Suppose the state contains four existing coal-fired units that generate equal amounts of electricity, each with a CO_2 emission rate of 2000 lbs/MWh. The average emission rate for those four units is 2000 lbs/MWh. One of the four units is then retired; however, the retired unit is replaced (or will be replaced in the near future) with a new NGCC unit. Then, due to increases in demand, an additional NGCC unit is constructed in the state. Both new NGCC units have a lower CO_2 emission rate of 1000 lbs/MWh. Under the proposed rule, in a rate-based state, the retirement of the coal-fired unit has no effect on the average CO_2 emission rate; nor does the addition of new NGCC plants. The average rate remains 2000 lbs/MWh (now averaged over 3 units). Only if the emission rate from the new NGCC units are accounted for would the state's average emission rate decrease to 1600 lbs/MWh. That decrease is a logical and desirable outcome, consistent with the goals of the proposed

[42] The proposed rule makes a distinction between "affected entities," and "affected EGUs." IUG is not arguing that a new NGCC plant should be considered an "affected EGU," as that term is defined in §60.5820.

rule. In order for states with rate-based goals to benefit from the utilization or increased utilization of new, lower-carbon EGUs, the rule must allow states to provide a mechanism to account for new units that otherwise are not subject to regulation under this rule. The easiest mechanism to accomplish this goal is for the rule to recognize all new NGCC plants as affected entities.

Compliance Issues: Building Block 3 – Expansion of Renewable Energy

Building Block 3 of EPA's "Best System of Emissions Reduction" is for states to use "an expanded amount of lower-carbon generating capacity."[43] To estimate the "best practices" for renewable energy use in any given state, EPA divides the country into six regions; Indiana is located in the North Central region, which also includes Illinois, Iowa, Michigan, Minnesota, Missouri, North Dakota, South Dakota, and Wisconsin. EPA uses region-wide rates of renewable energy use, and a region-wide average of renewable portfolio standards, to establish the rate at which states are expected to add renewable energy to their electricity sectors in the coming years. Using this method, EPA expects Indiana to increase its renewable energy portfolio from 3 percent of electricity generated in 2012 to 5 percent by 2020, and then to 7 percent by 2030.

In the proposed rule, EPA says the agency "has not assumed any specific type of renewable generating technology for the best practices scenario."[44] Not only has the agency not "assumed" a particular technology, EPA has yet to clarify which energy resources will qualify as "renewable" for the purposes of complying with the rule. Including or excluding certain resources could be problematic. For instance, biomass was counted as a zero-carbon resource for the purposes of establishing the 2012 baseline for existing renewable assets. EPA officials have suggested, however, that biomass might not be counted as a zero-carbon resource for the purpose of compliance. To the extent that such a mismatch makes its way into the final rule, EPA's assumptions regarding the trajectory of future renewable energy use will be unrealistic and arbitrary.

[43] See Proposed Rule, at page 34866.
[44] See Proposed Rule, at page 34866.

Adding significant renewable resources to the grid could create additional interconnection, congestion and dispatch problems, threatening the reliability of the electrical supply. Congestion is currently a problem for the 800+ wind turbines located in and around White County, Indiana.[45] This problem has been acknowledged by other U.S. federal agencies. For instance, a 2014 draft study on congestion by the U.S. Department of Energy found that in the Midwest "congestion results from high and growing levels of wind generation that cannot be delivered from western sources to more distant loads, and the lack of additional transmission to enable further development in renewable-rich areas."[46] IUG has no reason to believe EPA took these unique circumstances into consideration when drafting the proposed rule, which calls into question the appropriateness of the agency's expectations for Indiana.

EPA failed to take into account Indiana's unique potential for renewable energy use when they employed a regional average to calculate Indiana's growth rate. Just because Indiana's region might be able to achieve a 6 percent year-over-year growth rate in renewable generation does not mean that is an appropriate figure for Indiana. First, the proposed rule fails to make allowances for the substantial degree of political uncertainty that belies present-day growth in renewable energy generation. This oversight by EPA is a significant one: Independent experts have argued that uncertainty in the future of tax law and subsidies has a substantial impact on investment decisions in the solar industry, for instance.[47] Second, Indiana has limited solar resources. A 2013 SUFG report explains that "Indiana is in a region of the country that has the lowest annual average solar radiation."[48] This limits the potential for Indiana utilities to install utility-scale or community solar. Finally, EPA's assumptions about wind power might also be erroneous. Indiana has added significant wind power assets to its generation portfolio since 2008, and EPA assumes new capacity can continue to be added without difficulty. There is a risk

[45] "A bottleneck is bedeviling Indiana's mighty wind turbines." *The Indiana Lawyer*. February 26, 2014.
[46] "National Electric Transmission Congestion Study." U.S. Department of Energy. August 2014.
[47] "§1603 Treasury Grant Expiration: Industry Insight on Financing and Market Implications." National Renewable Energy Laboratory. June 2012. http://www.nrel.gov/docs/fy12osti/53720.pdf.
[48] "2012 Indiana Renewable Energy Resources Study." State Utility Forecasting Group. September 2012.

that the best siting locations are being used up, however, and that the price of producing an additional megawatt of wind power will ramp upward as more capacity is added.

EPA's approach to calculating region-wide renewable energy targets is flawed. Indiana, North Dakota, and South Dakota have renewable portfolio goals rather than renewable portfolio standards. Because EPA used an average of the region's existing renewable portfolio standards to calculate the feasible level of renewable energy that could be expected from each state in the region, EPA used non-Indiana benchmarks to set Indiana's goal under Building Block 3. In other words, EPA decided that state legislatures outside Indiana were qualified and able to correctly assess the future potential of Indiana's renewable energy sector when they were crafting policies for their own states. This notion is absurd.

IUG is also unaware of any feasibility assessment EPA employed when the agency elected to treat the benchmarks contained in existing renewable portfolio standards as achievable at a reasonable cost. It is important to note that simply because state legislatures in other Midwestern states are attempting to facilitate the installation of a certain amount of renewable energy in their states in the coming decades, success is not guaranteed. It is inappropriate to hold Indiana to an unproven standard decided by those other legislatures.

EPA has not clarified how the agency will account for renewable energy that is generated in one state but consumed in another. This problem is particularly salient in the case of Indiana, where wind energy produced in four other states is delivered across the state's borders. Of the 946 MW of wind power Indiana utilities had secured in power purchase agreements as of December 2013, 410 MW were produced out-of-state. The same problem also applies to multi-state arrangements: Were Indiana to participate in a regional compact for the purpose of complying with the proposed rule, serious issues might arise with respect to the allocation of renewable energy credits ("REC") between RTOs. EPA should clarify. EPA should specifically address the manner in which interstate REC markets will be assessed for the purpose of compliance with Indiana's 111(d) Plan.

Mandating new renewable generation capacity on a state-by-state basis presents the same "seam issues" for Indiana as mandating particular dispatch decisions (see above). Furthermore, EPA's decision to employ state-by-state goals for renewable energy complicates future investment decisions in generation assets that serve multiple jurisdictions. For instance, would both Indiana and Wisconsin be able to claim credit for investing in a wind farm in Wisconsin that provides power to both regions? If not, EPA risks creating a perverse incentive for the construction of sub-optimal renewable energy systems to manipulate the accounting scheme in the proposed rule. Additional clarification is necessary.

The "alternative approach" offered in the proposed rule does not solve these problems. In fact, EPA's methodology for calculating alternative state renewable energy goals is even more crude than its first approach. The proposed rule says: "Under this alternative RE approach, the EPA would quantify RE generation for each technology in each state as the lesser of (1) that technology's benchmark rate multiplied by the technology's in-state technical potential, or (2) the IPM-modeled market potential for that specific technology."[49] Theoretically, this approach is supposed to account for both technical and economic constraints in the deployment of renewable energy. In fact, the agency's use of generic and unrealistic assumptions regarding the "benchmark rate" renders the state goals that result from this methodology inappropriate. In the technical support document for the alternative approach, EPA explains that "the average development rate of the top third (16) of states is designated a benchmark RE development rate for each technology type."[50] If EPA believes separating the country into regions is important to account for differences in renewable energy potential, why does the agency also believe all states can mirror the renewable energy profiles of the sixteen states with the most installed capacity of each specific technology? Because the agency uses a generic and unrealistic benchmark rate in its calculations, Indiana's renewable energy target under the alternative approach is 20 percent of the

[49] See Proposed Rule, at page 34870.
[50] "Alternative RE Approach Technical Support Document." U.S. Environmental Protection Agency. June 2014. http://www2.epa.gov/sites/production/files/2014-06/documents/20140602tsd-alternative-re-approach.pdf.

state's electricity generation by 2030. That is nearly three times the number yielded by the agency's first approach!

In its NODA, the agency proposes a third approach to calculating state targets, which it refers to as the "regionalized approach." The NODA is vague on the details, but the agency's general proposal is to "[sum] the RE target generation identified under the alternative approach in the June 2014 proposal for all states in [each] region; and then [to reallocate] that summed generation proportionally to each state within that region."[51] Because the methodology used in the alternative approach is flawed, any state-by-state allocation of targets derived from the alternative approach is also flawed. Worse, the use of regional averages based on the alternative approach combines the problems with both of the approaches contained in the proposed rule, because both national and regional averages are inappropriately applied to Indiana's unique electricity generation mix. EPA should refrain from conflating renewable energy data from different states altogether.

The NODA also suggested that EPA is considering subtracting new renewable energy generation assets from the 2012 baseline for each state's energy demand when calculating states' rate-based emissions targets. The agency's reasoning is that the current approach "does not clearly indicate whether, and to what extent, that generation will replace existing fossil generation as opposed to future generation increases from existing sources."[52] Pretending that renewable energy offsets existing fossil fuel generation to any appreciable extent would be an exercise in willful ignorance by EPA, as empirical data suggests intermittency and demand fluctuations nullify any supposed zero-sum relationship. Additionally, offsetting renewable energy against the baseline would exacerbate all of the other problems with the agency's calculations for Building Block 4, by requiring an absolute reduction in demand every year between now and 2030.

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[51] "Notice of Data Availability Related to the Proposed Clean Power Plan." October 28, 2014. http://www2.epa.gov/sites/production/files/2014-10/documents/20141028noda-clean-power-plan.pdf.
[52] See Notice of Data Availability, at page 64552.

Compliance Issues: Building Block 4 – Energy Efficiency

Building Block 4 of EPA's "Best System of Emissions Reduction" is for states to implement demand-side energy efficiency measures. Specifically, EPA asserts that every state can achieve net energy savings of 1.5 percent, year-over-year, for the years 2017 to 2027.[53] For states that have already achieved 1.5 percent year-over-year energy savings from their current efficiency programs, EPA merely requires that they continue at their present rate of savings throughout the period 2017-2027. For states like Indiana that have not achieved that rate of savings, EPA expects a "ramp-up" to 1.5 percent using savings rates that increase by 0.2 percent per year.[54]

EPA expects Indiana to achieve cumulative reductions in residential, industrial, and commercial energy usage of 3.2 percent by 2020 and 11.1 percent by 2030. These numbers are based on a set of flawed assumptions about Indiana's electricity sector and would be incredibly costly to achieve. IUG proposes EPA conduct a more realistic appraisal of the potential for realizable energy savings in Indiana based on state-specific forecasts. IUG also proposes EPA take Indiana's existing demand-side efficiency programs into account when crafting their expectations for future energy savings.

To better understand why EPA's 1.5 percent number is inappropriate for Indiana, it helps to understand the history of demand-side efficiency programs in our state. In December 2009, the IURC mandated that Indiana utilities implement a set of statewide demand-side management programs ("CORE programs") to achieve energy savings equivalent to a 2 percent reduction in sales by the year 2019, with interim goals. The savings benchmarks required by this program, expressed in gross terms, were as follows:[55]

[53] See Proposed Rule, at page 34872.
[54] See Proposed Rule, at page 34873.
[55] "Phase II Order." Indiana Utility Regulatory Commission, Cause No. 42693. December 9, 2009. http://www.in.gov/iurc/files/Phase_II_decision_in_Cause_No._42693.pdf.

Year	Annual electric savings goal (% of weather-normalized average electric sales for prior three years)
2010	0.3%
2011	0.5%
2012	0.7%
2013	0.9%
2014	1.1%
2015	1.3%
2016	1.5%
2017	1.7%
2018	1.9%
2019	2.0%

According to the evaluation completed to measure energy savings through the CORE programs, in 2012 (the first year such programs were offered on a statewide basis) Indiana achieved an "overall verified program realization rate of 71 percent for kWh and 60 percent for kW."[56] In other words, through its statewide programs, Indiana achieved less than 0.7 percent verified energy savings in 2012. Indiana has a very limited history in large-scale energy efficiency programs, making it difficult to know the long-term achievability of energy efficiency goals. Yet, in spite of these facts, EPA calculated that Indiana was one of twelve states that "have either achieved—or have established requirements that will lead them to achieve—annual incremental savings rates of at least 1.5 percent of the electricity demand that would otherwise have occurred."[57] The existence of a state requirement to achieve 1.5 percent savings at some point in the future is a far cry from demonstrating that requirement's feasibility or cost-effectiveness.

Recent events in Indiana support IUG's skepticism towards EPA's aggressive savings target. This year, the Indiana General Assembly elected to reevaluate the specifics of the state's energy efficiency

[56] "2012 Energizing Indiana Programs: EM&V Report." Prepared for The Indiana Demand Side Management Coordination Committee. June 20, 2013. http://aceee.org/files/pdf/2012-indiana-emv-report.pdf.
[57] See Proposed Rule, at page 34872.

programs. Specifically, Senate Bill 340 established a sunset for the aforementioned goals, effective December 31, 2014. Had those benchmarks remained in place, a study by the Energy Center of Wisconsin estimated the cost of compliance would have spiked to $200 million in 2015 and $549 million in 2019.[58]

Indiana has already taken advantage of many of the easiest opportunities to improve statewide energy efficiency. For instance, in addition to utility-specific programs, through the CORE programs created by the IURC in 2009, utilities and stakeholders have been aggressively marketing residential home energy audits; low-income weatherization; building assessments at schools; residential lighting improvements; and commercial & industrial prescriptive rebates for several years. These efforts are widespread and impactful; in fact, the SUFG cites utility-sponsored conservation efforts as having a major influence on the overall resource needs of Indiana in 2013.[59] To date, the vast majority of verified savings have come from residential lighting improvements and commercial & industrial prescriptive rebates. Both of these programs promise diminishing returns in the years to come.

In the case of residential lighting improvements, savings are realized when the light bulb is changed. The opportunities for year-over-year improvements are limited by the nature of the technology. In the case of commercial & industrial prescriptive rebates, major retrofits like equipment replacement or building improvements are also often one-time opportunities. As more and more major efficiency improvements are implemented by a facility, improvements tend to yield fewer savings per dollar invested. This makes intuitive sense; both electricity consumers and utilities have an incentive to implement the least-expensive, highest-magnitude savings options first. Other measures besides lighting and equipment improvements have no track record of being sustained and/or growing annually, or face

[58] "Indiana's Core and Core Plus Energy Efficiency Programs: Benefits, Costs, and Savings." Energy Center of Wisconsin. August 14, 2014.
http://www.in.gov/iurc/files/DSM_Report_to_General_Assembly_w_Cover_Letter_8-15-2014(1).pdf.
[59] "Indiana Electricity Projections: The 2013 Forecast." State Utility Forecasting Group. December 2013.

consumer acceptance problems. Inexplicably, EPA assumes that existing opportunities for improvements in energy efficiency will be continuously available for a decade.

Federal lighting standards will make it harder for Indiana to include residential lighting improvements in its 111(d) Plan. Specifically, the Energy Independence and Security Act of 2007 (H.R. 6) set new light bulb efficiency standards that have largely resulted in the phase-out of traditional incandescent bulbs. Other federal building codes and efficiency standards will have a major impact on the marketplace for appliances and household products in the coming years. These standards will result in energy savings in Indiana, but Indiana cannot claim those savings in its 111(d) Plan because those savings programs are not "realized exclusively through the adoption and implementation" of Indiana demand-side efficiency programs.[60] Under the proposed rule, Indiana is effectively being penalized for the state's past investments in energy efficiency.

There are significant evaluation, measurement, and verification ("EM&V") concerns associated with EPA's savings target. Because the proposed rule credits net savings, rather than gross savings, Indiana will need to carefully track consumer behavior to determine which energy savings to attribute to the state's demand-side programs. This process is arduous and expensive. Indiana's experience with statewide EM&V demonstrates that audited and verified savings sometimes differ greatly, even for a small number of efficiency programs. Furthermore, traditional EM&V is largely applied to jurisdictional utilities in Indiana. It generally is not applied or required for other energy efficiency programs such as REMCs or projects undertaken by large industrial sources without participating in a utility-sponsored effort. These sources would likely be resistant to accepting enforceable EM&V and are not under the jurisdiction of the IURC. Thus, a "one size fits all" EM&V approach would likely be a barrier to capturing credit for a significant amount of energy efficient beyond jurisdictional utilities. These issues are but several of many questions left unanswered by the proposed rule's discussion of EM&V.

[60] See Proposed Rule, at page 34872.

As an alternative to EM&V, IUG recommends that EPA employ a weight of evidence approach to calculate energy savings. This approach is referenced in EPA's publication, "Roadmap for Incorporating Energy Efficiency/Renewable Energy Policies and Programs into State and Tribal Implementation Plans, Appendix H: Weight of Evidence Pathway." EPA has used this approach before as a way to demonstrate compliance with CAA regulations.[61] In the case of CO_2, a weight of evidence approach would avoid many of the implementation issues and jurisdictional problems associated with traditional EM&V. EPA should clarify how it will evaluate states' methodologies for calculating energy savings from demand-side efficiency programs before states are required to submit their 111(d) Plans.

To calculate demand-side energy efficiency's ability to help states reach their CO_2 emissions targets, EPA "estimated that each state's annual incremental savings rate increases from its 2012 annual saving rate."[62] IUG believes the decision to use 2012 as a baseline for energy consumption is ill-conceived, because it effectively penalizes any efficiency initiatives that Indiana undertakes between 2012 and 2017. Because energy efficiency programs get more expensive as additional savings are realized, the most cost-effective option for states is to preserve easy improvements until they can be counted towards compliance with the proposed rule. Indiana would be incurring unnecessary costs if the state took steps to realize net energy savings between now and 2017. The incentive structure of the proposed rule errs strongly towards inaction, precisely the opposite of its intended effect. EPA has acknowledged this issue in the proposed rule, and is seeking comment on the best way to avoid a perverse incentive. One option is to give states credit for programs that are already in place that will result in emissions reductions during the compliance period.[63] This re-formulation would be a step in the right direction.

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[61] "Guidance on the Use of Models and Other Analyses for Demonstrating Attainment of Air Quality Goals for Ozone, PM2.5, and Regional Haze." U.S. Environmental Protection Agency. April 2007. http://www.epa.gov/ttn/scram/guidance/guide/final-03-pm-rh-guidance.pdf.
[62] See Proposed Rule, at page 34872.
[63] See Proposed Rule, at page 34839.

2012 may also be an inappropriate baseline for realizable energy savings for reasons related to demand. Consider that Indiana's total energy supply was lower in 2012 than in any year since 1996, according to EIA data.[64] If EPA expects Indiana to achieve net year-over-year energy savings relative to demand in 2012, EPA should take into account the conditions that produced peculiar demand-side conditions that year. Otherwise, the agency's estimates for future consumption will not reflect the restoration of "normalcy" to Indiana's energy markets in 2013 and 2014 and the state will be penalized for macroeconomic developments outside its control. IUG believes a multi-year average would result in a more appropriate baseline figure for Building Block 4. There is precedent for the use of a multi-year average in other EPA environmental regulations.[65] EPA should take industry input into consideration when formulating an appropriate timeline for use in its revised calculations.

In the proposed rule, EPA asserts that "reducing demand for generation at affected EGUs through policies to improve demand-side energy efficiency is a proven basis for reducing CO_2 emissions at those EGUs."[66] If overall CO_2 emissions are taken into account, and not just emissions at EGUs, electric vehicle use may represent a notable and overlooked exception to this statement. According to EPA's website, electric vehicle use increases demand for electricity while reducing aggregate CO_2 emissions.[67] IUG is concerned EPA may be penalizing Indiana's efforts to increase the state's use of electric vehicles. This concern has immediate implications for Indiana; Indianapolis, for example, has put multiple programs in place to incentivize the installation of electric vehicle charging stations.[68] EPA should avoid penalizing these investments, which are certainly in line with the Agency's goal of curtailing greenhouse

[64] "Indiana Electricity Profile 2012: Table 10. Supply and disposition of electricity, 1990-2012 (million kilowatthours)." U.S. Energy Information Administration. http://www.eia.gov/electricity/state/Indiana/.
[65] "Area Designations for 1997 Ground-level Ozone Standards." U.S. EPA. November 12, 2013. http://www.epa.gov/airquality/ozonepollution/designations/1997standards/index.htm.
[66] See Proposed Rule, at page 34871.
[67] "Explaining Electric and Plug-In Hybrid Electric Vehicles." U.S. EPA. August 21, 2014. http://www.epa.gov/greenvehicles/about/explain.htm.
[68] "Electric Car Share Program." The City of Indianapolis. Accessed October 9, 2014. http://www.indy.gov/eGov/Mayor/initiatives/Pages/Electric-Vehicles0124-4069.aspx.

gas emissions. It would be ironic if EPA asserted the authority to regulate energy use "beyond the fence-line" in the name of reducing emissions only to disregard the proposed rule's impact on emissions everywhere except at the EGU.

Another example where the agency risks a double-standard of this sort is "out-of-sector" offsets. EPA fails to allow out-of-sector offsets to be used to comply with emissions standards under a state plan, thereby foreclosing a compliance option of unquestionable environmental benefit. The agency concedes, however, that every existing cap-and-trade program allows for allowances to be used for compliance purposes. EPA reconciles this discrepancy by allowing out-of-sector offsets to be retained under those plans and included under new plans – but not for compliance with the proposed rule. EPA justifies this unusual and contradictory policy on the basis that "all of the emission reduction measures included in the agency's BSER reduce CO_2 emissions from affected EGUs," whereas out-of-sector offsets apparently do not.[69] EPA's distinction is a blurry one. It is difficult to understand how EPA can determine that greenhouse gas reductions from offsets owned and operated by EGUs do not "come from" EGUs, yet theoretical reductions resulting from market effects in the form of demand-side energy efficiency do "come from" EGUs. Out-of-sector carbon offsets have proven to be a simple and verifiable means to reduce greenhouse gases and should be included in EPA's compliance calculations.

Conclusion

The proposed CAA rule covering carbon emissions from existing coal-fired power plants stretches EPA's legal authority well beyond applicable statutory provisions and precedent. While EPA stresses flexibility, in reality the proposed rule puts the agency on course to intrude on matters reserved to the states. These intrusions interfere with the effective management of the electrical system, particularly in the case of states like Indiana in which coal-powered generation makes an important contribution to the energy mix. The proposal relies upon unrealistic and unproven assumptions

[69] See Proposed Rule, at page 34910.

regarding heat rate, energy efficiency, natural gas, and renewable energy. The agency has been less than transparent about their modeling of cost and supply impacts for Indiana. We strongly recommend that the rule be withdrawn and that the agency consider more streamlined and legally defensible alternatives.