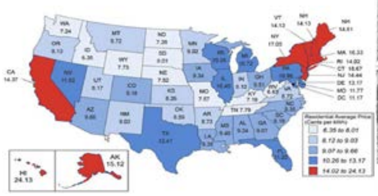
State Implementation of CO_2 Rules

Institutional and Practical Issues with State and Multi-State Implementation and Enforcement



A White Paper

Release 2.0 – November 2014

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Executive Summary

The proposed rule implicates potentially impossible timelines. States have relatively little time to make crucial decisions regarding EPA's proposed rule, including whether to act individually or on a multi-state basis, which of four state plan pathways to take, what state agency(ies) should be responsible to implement a Carbon IRP-like process, how any ISOs or RTOs operating within the state will play a role, and what enforcement and corrective action measures are necessary to ensure compliance with the proposed rule.

'Carbon IRPs' will require new institutional arrangements and state legislation. States will need to devise institutional arrangements, which almost certainly will require new legislation, between the state PUC and state environmental regulator to implement carbon-driven integrated resource planning.

All EGUs need to be in the room for a Carbon IRP process to be effective – including non-jurisdictional entities not traditionally subject to regulation. State plans will need to encompass all electric generation units, including those owned or operated by current non-state jurisdictional entities like rural cooperatives and municipal utilities. To the extent a state plan relies on energy efficiency or demand response, all distribution utilities will need to be brought within carbon IRP planning as well.

Carbon-driven planning may result in a soft reintegration of restructured markets. Restructured wholesale markets will require integrated carbon planning across the market areas to ensure adequate capacity and reliability.

While the NODA proposes to ease the 2020-2029 glide path, it also contains potentially significant modifications to the ultimate 2030 CO_2 performance goal. The potential glide path modifications must be counterbalanced with potential changes to each state's CO_2 performance goal at the end of the glide path. Potential "holistic" or regional assessments to calculate Building Block 2 (gas) and Building Block 3 (renewables) assumptions may result in more stringent targets.

The NODA increases the pressure to adopt multi-state plans or regional solutions. States that cannot fundamentally overhaul their generation fleets to meet the "potential renewable" or "holistic" assumptions will be pushed to seek out state partners to create a multi-state plan that allows them to take advantage of existing NGCC capacity or a more robust renewable energy portfolio in another state. This push towards regional solutions fails to contemplate whether they make sense from an electric interconnection or regulatory standpoint, and overlooks the states' rivalrous interests.

Multi-state plans will breed rivalrous scenarios, and EPA approval criteria will require interstate enforcement mechanisms, which implicate the Compact Clause. Because state interests will be inevitably rivalrous, multi-state plans will need an enforcement mechanism and may well require congressionally-approved interstate compacts to satisfy EPA requirements of enforceability.

Federal Section 111(d) plans may put state regulators in awkward positions and force ultra vires actions. State plans that are adjudged by EPA to be inadequate in terms of enforceable, quantifiable and verifiable reductions of EGU CO_2 emissions equivalent to EPA's goals, and implementation of corrective actions, if necessary, will result in a FIP. A federal plan creates legal issues of whether EPA has the authority to force state officials to enforce obligations they do not have authority to enforce under state law, and to engage in resource planning and direct system dispatch.

I. Background and Release 2.0

This Release 2.0 of our Section 111(d) White Paper incorporates feedback from the original paper, and also updates the analysis to include the Notice of Data Availability (NODA), issued by EPA on October 28, 2014.[1] Release 2.0 also synthesizes our thinking from the three additional white papers addressing existing state legislation, general state institutional issues, and specific issues with municipal utilities and cooperatives.

We continue to foresee significant institutional challenges for the states. States will still need to:

- Pass enabling legislation to implement the proposed rule at the state level.
- Construct institutional arrangements between the universe of regulators (public utility commissions (PUCs), environmental regulators, gubernatorial energy offices) in a state statutory and administrative context.
- Obtain and concentrate jurisdiction in the appropriate regulatory bodies over all affected entities, including in many states non-jurisdictional entities like cooperatives and municipal utilities.
- Institute carbon-driven resource planning and dispatch in restructured markets to ensure adequate capacity and reliability.
- Structure enforceable and constitutional multi-state Section 111(d) plans with interstate enforcement mechanisms, which may well require Congressionally-approved interstate compacts to satisfy EPA state plan approval criteria.

This Release 2.0 focuses on developments since the initial release, specifically individual state institutional analyses, reliability issues, and potential changes to the proposed CO_2 Emission Guidelines from the NODA.

II. State-by-State Institutional Analyses

Here, we have embarked on a series of brief state essays illustrating the regulatory fragmentation that exists in several states (Colorado, Illinois, Kentucky, Montana, and Pennsylvania), focusing on the respective legal authority of environmental/air regulators and PUCs. The issues in the states detailed here are likely indicative of analogous institutional fragmentation in other states. These state essays are included in Appendix A. Each state essay looks at the relevant regulatory structure in each state, including the applicable statutory authorities of environmental and air regulators and PUCs. The essays also consider consequences of *ultra vires* action, as well as the need for state legislation in each state.

III. Reliability Issues

Release 1.0 stressed the importance of PUC involvement given potential reliability issues associated with the implementation of a Section 111(d) state plan. Since EPA issued the proposed CO_2 Emission Guidelines, numerous entities and state regulators have weighed in on the reliability implications, both regionally and on a state-specific basis. A compilation of these comments is included as Appendix B, and these comments underscore the initial conclusion that reliability considerations will be paramount as state Section 111(d) plans are developed and implemented. In addition, whether entities have identified serious reliability concerns or not, the interconnected nature of these reliability issues with the regulation of CO_2 emphasizes the need for new state institutional arrangements that allow these issues to be fully-vetted by appropriate regulators. This illustrates one of many issues created by EPA's broad construction of the best system of emission reduction (BSER) under Section 111(d), with the proposed CO_2 Emission Guidelines functioning as an energy policy rather than a traditional Clean Air Act rule. Finally, the issues raised in the NODA may result in more stringent state-by-state CO_2 performance goals, which could have additional reliability implications. The reliability comments and analyses to date are based solely upon the initial proposal and do not factor in any implications of the NODA.[2] The NODA and its potential effects may exacerbate existing reliability concerns if and when

[1] 79 Fed. Reg. 64,543 (Oct. 30, 2014).

[2] 79 Fed. Reg. 64,553 ("[A]t least some of these alternative applications of the target-setting equation would result in many states having tighter rate-based goals.")

state CO_2 performance goals become more stringent through any of the proposed changes in the NODA.

IV. The NODA

The NODA released in late-October represents the most significant change to EPA's proposal. The NODA raises numerous issues, including potential changes to the 2020-2029 glide path, revisions to the CO_2 performance goal-setting formula, and regional and/or "holistic" approaches to calculating the Building Block 2 and Building Block 3 assumptions. In short, the NODA could result in some short-term relief for the states, but with ultimately lower rate-based goals through "potential renewables" and "holistic gas" analysis.

a. The Give with the Glide Path

The NODA discusses the possibility of near-term relief with the 2020-2029 interim goal by (1) allowing credit for early CO_2 emission reductions (resulting in a deferral of additional CO_2 emission reductions to later in the 2020-2029 period) or (2) phasing-in Building Block 2 assumptions over time rather than assuming a 70% utilization rate could be achieved by 2020.[3] Early reductions may include renewable energy or demand side projects or initiatives that would be implemented prior to 2020.[4] As to the phase-in, Building Block 2 would be treated in the same way as Building Blocks 3 and 4 in the proposed CO_2 Emission Guidelines. Emission reductions tied to increased NGCC utilization would be factored into the interim goal on an incremental basis.

These potential modifications to the 2020-2029 glide path would provide compliance relief on the front end. These changes address EPA's goal of "ensur[ing] that the overall framework includes sufficient flexibility, particularly with respect to timing of and strategies for reducing emissions from the affected units so that states can develop cost-effective strategies, and states, utilities, grid operators and others can readily respond to unexpected changes or demands on the energy system, such as severe weather."[5] Further, EPA requests comment on a potential phase-in of Building Block 1, although there is little discussion of the mechanics of this approach in the NODA.[6]

b. The Take with the Glide Path

The potential glide path modifications must be counterbalanced with potential changes to each state's CO_2 performance goal at the end of the glide path. Potential "holistic" or regional assessments to calculate Building Block 2 (gas) and Building Block 3 (renewables) assumptions may result in more stringent ultimate targets, as discussed in more detail below. Moreover, some of the proposed changes to the "goal-setting equation," *i.e.*, the 2030 CO_2 performance goal, combine with the Building Block 2 and Building Block 3 modifications to create the possibility of substantially more stringent goals. Perhaps the most significant is a formula change meant to respond to concerns from stakeholders that "by holding existing fossil generation and the corresponding emissions at 2012 levels, and not reducing them based on the amounts of incremental RE and EE, the state goals fail to reflect the full potential, under the BSER, for incremental RE and EE to replace fossil steam generation."[7] In the proposed CO_2 Emission Guidelines, EPA added incremental renewable energy and energy efficiency to the denominator of the state goal formula. This is different than the approach for incremental NGCC generation under Building Block 2, which "was assumed to reduce carbon intensity by replacing generation from 2012 levels."[8] The alternate proposal in the NODA is to have incremental renewable energy and energy efficiency calculated under the Building Block 3 and Building Block 4 assumptions "directly replace[] 2012 fossil generation levels and the corresponding emissions on a pro rata basis across generation types (*i.e.*, fossil steam and gas turbine)."[9]

A *pro rata*, direct replacement methodology represents a significant change from the initial goal-setting formula. EPA concedes that "[a]lthough the incremental generation levels assumed for building blocks 3 and 4 would not change under this approach, this adjustment to the goal-setting formula *would yield more stringent state goals*."[10] This may well offset, or even exceed, any interim benefit obtained from potential changes to the glide path calculation. Moreover, it places utilities in a difficult and unprecedented situation. A utility must conduct, evaluate and approve long-term resource planning in a world driven by a CO_2 performance goal predicated on

[3] 79 Fed. Reg. at 64,545.
[4] 79 Fed. Reg. at 64,545.
[5] 79 Fed. Reg. at 64,545.
[6] 79 Fed. Reg. at 64,548.
[7] 79 Fed. Reg. at 64,552.
[8] 79 Fed. Reg. at 64,553.
[9] 79 Fed. Reg. at 64,552.
[10] 79 Fed. Reg. at 64,552 (emphasis added).

a formula that directly interchanges baseload generation for intermittent generation or potential reductions through energy efficiency.

From an institutional standpoint, the potential one-for-one tradeout of baseload resources for renewable and energy efficiency resources taxes the ability of state air regulators beyond the breaking point. While a state air regulator has primary jurisdiction in the first instances over a Section 111(d) plan, that same regulator has no experience or competency with electric reliability or rate impact. A state, therefore, will have the institutional choice to make, whether it wants to task its air regulator with becoming a totalistic electric resource planner, or not. Further, as state-specific legal analysis shows, in most cases the air regulator does not have state law authority to author and enforce a plan using Building Blocks 2, 3 and 4 in any event.

A CO_2 performance goal calculated under the NODA tilts toward greater involvement of PUCs with their relative expertise with regard to system reliability, cost recovery issues and resource planning[11] in evaluating state plans. It further underscores the need for some type of adjudicatory process or contested case proceeding for state plans that allows these types of issues to be fully- and publicly-vetted. That said, the political economy of state regulation may not admit the PUC/air meta-regulator from coming into being. Traditionally, non-jurisdictional municipal and cooperative utilities have an abiding allergy to PUC regulation; investor-owned utilities may prefer PUC primacy because of experience and the ability to ensure rate recovery.

For restructured markets, the NODA continues to push toward a multi-state plan (the NODA pushes vertically-integrated states to multi-state solutions too, *see infra.*). Multi-state solutions suffer from many of the same political economy infirmities between the states. State interests for a Section 111(d) plan are rivalrous; not cooperative. Finally, to be enforceable, Compact Clause issues must be addressed.

c. *Increased Regionalization*

The hallmark of the NODA is its strong push towards regionalization and multi-state plans through the use of regional and nationwide assumptions to calculate each state's individual CO_2 performance goal. Specifically, EPA emphasizes issues with both Building Block 2 (increased NGCC utilization) and Building Block 3 (increased renewable energy penetration). EPA notes that its "intent is not to require regional plans."[12] However, the agency further points out that each state's CO_2 performance goal will be impacted by regionalization of certain assumptions and performance goals will not be based solely upon what is purportedly achievable in-state: "The EPA acknowledges that determining the component of the BSER related to shifting generation from fossil fuel-fired units to renewable units based on regional considerations or allocations among states could result in changes to state's goals relative to a non-regional approach."[13]

d. *Holistic and/or Regional Building Block 2 Assumptions*

With regard to Building Block 2, EPA issued the NODA, in part, to respond to "a number of stakeholders [that] have suggested that building block 2 should not focus purely on re-dispatch, but instead should focus more comprehensively or holistically on the use of natural gas as a means of reducing CO2 from the power sector. This concept may go beyond ideas raised in the original proposal …."[14] 'Going beyond' the Building Block 2 assumptions in the proposed CO_2 Emission Guidelines, *i.e.*, a "holistic approach," appears to be driven by an attempt to increase "the obligation of those states with little or no NGCC generating capacity to employ natural gas beyond what the EPA included in the proposed rule, including the construction and/or increased utilization of new NGCC units and additional co-firing of natural gas at existing fossil steam units."[15] The proposed approach would create a "minimum value as a floor for the amount of generation shift for purposes of building block 2."[16] In other words, there is a fuel-switching or co-firing baseline that every state must meet regardless of the current makeup of its generation fleet. Based on EPA's

[11] In considering the need for adjudicatory processes, it is worth noting that some PUCs have approval authority over resource plans following an adjudicatory process, while in some states utilities merely present 'informational' resource plans.

[12] 79 Fed. Reg. at 64,549.
[13] 79 Fed. Reg. at 64,549.
[14] 79 Fed. Reg. at 64,546.
[15] 79 Fed. Reg. at 64,549.
[16] 79 Fed. Reg. at 64,550.

analysis, a figure between 12% and 55% could be an appropriate baseline. EPA provides an illustration using a state with no NGCC capacity and a 12% Building Block 2 floor: "To illustrate this minimum approach, if the lower quartile value were used, a state with 100 MWh of fossil generation and no existing NGCC generation in 2012 would have a state goal premised on 12 MWh shifting from higher-emitting to lower emitting NGCC generation."[17]

EPA also makes reference to a different, region-driven approach to Building Block 2. In the proposed CO_2 Emission Guidelines, EPA calculated proposed state CO_2 performance goals for Building Block 2 by applying the NGCC utilization assumptions on a state-by-state basis.[18] The agency also sought comment on whether Building Block 2 should be applied on a regional basis, and the NODA specifically calls out this alternate approach as "another possible mechanism for addressing stakeholders' concerns about the disparity of the impact of building block 2 between states that have already invested significantly in developing NGCC generation and those that have not."[19] EPA appears to distinguish this regional approach raised in the initial CO_2 Emission Guidelines from the "holistic," *i.e.*, national, approach with a minimum NGCC floor value outlined above. EPA notes that it could determine "appropriate levels of generation shift" under this Building Block 2 approach by looking at regional boundaries as defined by the North American Electric Reliability Corporation (NERC), Regional Transmission Organizations (RTOs), "or some alternative regional structure …."[20] To be sure, this regional approach is not a new proposal in the NODA. However, the renewed emphasis on what was initially set forth as an alternate proposal in the CO_2 Emission Guidelines is indicative of the regionalization inertia in the NODA.

e. Building Block 3 and Potential-Driven Assumptions

The regionalization theme was already a key component of the Building Block 3 assumptions in the proposed CO_2 Emission Guidelines. The NODA builds on this theme and offers "a conceptual discussion of a third methodological approach that some stakeholders have suggested and we refer to here as a regionalized approach."[21] This approach hinges on development potential and "adjusts each state's RE target based on the RE potential available across a multi-state region in which the state is located."[22] EPA explains the Building Block 3 calculation methodology under this approach:

> This regionalized approach could group states into regions; aggregate RE generation potential across states within each region; and then reapportion the aggregate identified RE generation to individual states according to criteria that assume regional RE development in which parties in multiple states participate, regardless of the specific state where the generation occurs.[23]

One potential approach to reallocation after the regional aggregation of "potential" renewable energy development is based upon consumption, *e.g.*, "each state's share of total electricity sales within that region in 2012."[24] The "potential" methodology is directed at stakeholder concerns regarding the allocation of renewable resources for purposes of Building Block 3,

[17] 79 Fed. Reg. at 64,550.
[18] 79 Fed. Reg. 34865, 34899 (June 18, 2014).
[19] 79 Fed. Reg. at 64,547.
[20] 79 Fed. Reg. at 64,550-51 (citing back to the proposed CO_2 Emission Guidelines at 79 Fed. Reg. 34,865 n. 142).

[21] 79 Fed. Reg. at 64,551.
[22] 79 Fed. Reg. at 64,551.
[23] 79 Fed. Reg. at 64,551. EPA notes that one potential grouping of states into regions would be that set forth in the proposed CO_2 Emission Guidelines. 79 Fed. Reg. 34,866-67. These groups are:

- East Central: Delaware, District of Columbia, Maryland, New Jersey, Ohio, Pennsylvania, Virginia, West Virginia.
- North Central: Illinois, Indiana, Iowa, Michigan, Minnesota, Missouri, North Dakota, South Dakota, Wisconsin.
- Northeast: Connecticut, Maine, Massachusetts, New Hampshire, New York, Rhode Island, Vermont.
- South Central: Arkansas, Kansas, Louisiana, Nebraska, Oklahoma, Texas.
- Southeast: Alabama, Florida, Georgia, Kentucky, Mississippi, North Carolina, South Carolina, Tennessee.
- West: Arizona, California, Colorado, Idaho, Montana, Nevada, New Mexico, Oregon, Utah, Washington, Wyoming.
- Miscellaneous: Alaska and Hawaii were considered as two individual regions. 79 Fed. Reg. at 64,551, n. 11.

[24] 79 Fed. Reg. at 64,551. EPA notes that a different reallocation approach would be based upon total generation in each state for 2012. *Id.*

specifically with regard to out-of-state resources and whether the state that hosts the resource should receive credit or if the state compelling the generation should receive such credit.[25]

The proposed CO_2 Emission Guidelines considered in-state generation potential under Building Block 3,[26] but the regional approach makes states ever more interdependent on one another and the methodology for determining "potential" remains vague. Many states' renewable potential is limited by infrastructure issues that constrain the ability to bring "potential" renewable energy to load. This is particularly true in the western U.S. for utility-scale projects, which would likely be favored by state plans to achieve the most cost-effective generation considered in the Building Block 3 assumptions.

As previously discussed in the White Paper series, states are not required to satisfy the assumptions in the Building Blocks. Nevertheless, the inability to deliver significant amounts of "potential" renewable energy generation due to infrastructure limitations has a two-fold effect. First, it makes it more difficult to meet a state CO_2 performance goal premised upon bringing all "potential" renewable energy on-line. Second, it may make states more dependent on neighboring states to backfill the emission reduction shortfall created by infrastructure limitations.

f. Practical Effects

EPA accurately represents that the potential changes to the NODA do not "require regional plans." However, there are significant practical effects of the new proposals, or increasingly emphasized existing proposals, under Building Block 2 and Building Block 3. States that cannot fundamentally overhaul their generation fleets to meet the regional or "holistic" assumptions will be pushed to seek out state partners to create a multi-state plan that allows them to take advantage of existing NGCC capacity or a more robust renewable energy portfolio in another state. The potential changes to these assumptions push states towards regional solutions, regardless of whether they make sense from an electric interconnection or regulatory standpoint.

On the latter point, EPA and many commenters continue to avoid the institutional regulatory issues in comments and address the proposed CO_2 Emission Guidelines as a compliance math problem. This math problem will become more complicated if, as predicted by the NODA, "at least some of these alternative applications of the target-setting equation … result in many states having tighter rate-based goals."[27] As the math problem becomes more difficult, the state institutional issues become ever more vital to ensure that cost and reliability are adequately evaluated by appropriate regulatory institutions.

The NODA's implicit push towards the use of multi-state plans or aggregated CO_2 performance goals implicates all of the Compact Clause considerations raised in Release 1.0. This Constitutional matter, as with the state-level institutional issues, remains underdeveloped by EPA and in the general discourse on the proposed CO_2 Emission Guidelines.

V. Conclusion

The NODA injects significant new issues and considerations into the Section 111(d) rulemaking, and underscores the vital state institutional issues raised by the proposed CO_2 Emission Guidelines. The legal issues remain the same (as well as largely unaddressed), but as state CO_2 performance goals potentially "tighten" the need for appropriate regulators to participate in and evaluate state Section 111(d) plans takes on increased importance. Significant reliability analyses have already occurred, but the NODA may harbor further implications for the reliability issues raised by the proposed rule.

Many states continue to approach the proposed CO_2 Emission Guidelines in a 'math problem' vacuum, but state institutional issues will become more imperative following the December 1, 2014 comment deadline as state-level focuses shift to implementation amid quickly approaching state legislative sessions.

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[25] *See, e.g.*, 79 Fed. Reg. at 64,547. ("Stakeholders have expressed interest in a target-setting methodology that takes into account interstate exchanges of RE in the calculation of state goals, on the premise that such an approach would better align with existing state RE policies and potential claims on a given state's RE generation by parties from other states (such as renewable energy certificates and power purchase agreements). This feedback has been received both from states that are net suppliers of RE generation to other states and from states that are net consumers of RE generation produced in other states.")

[26] 79 Fed. Reg. at 64,547, n. 3.

[27] 79 Fed. Reg. at 64,553.

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Appendix A

Colorado Regulatory Authorities

Interaction with Clean Air Act Section 111(d)

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This Paper briefly addresses four questions regarding the authority of the Colorado Public Utilities Commission (PUC), Colorado Department of Public Health and Environment (CDPHE), and Air Quality Control Commission (AQCC) to implement EPA's proposed rule addressing carbon dioxide emissions from existing sources under Section 111(d) (CO_2 Emission Guidelines) of the Clean Air Act (CAA).[1] It first analyzes the scope of CDPHE and AQCC's delegation to implement the CAA, followed by an analysis of the PUC's regulatory authority. It also considers whether there is any ability for agencies to operate outside of their delegated authority. Finally, it evaluates whether legislation is necessary to implement and enforce any state plan developed pursuant to the proposed CO_2 Emission Guidelines. We conclude that Colorado will need to pass legislation to implement a state plan that uses anything beyond Building Block 1-only.

I. CDPHE Authority and EPA's Building Blocks

CDPHE and its Air Pollution Control Division (APCD), acting pursuant to regulations approved by the AQCC, has authority over air quality issues and compliance for certain generating sources owned by these entities. AQCC regulations prescribe the scope of activities of CDPHE and APCD, and Colorado law provides the AQCC with authority to "adopt, promulgate, and from time to time modify or repeal emission control regulations which require the use of effective practical air pollution controls: (I) For each significant source or category of significant sources of air pollutants; (II) For each type of facility, process, or activity which produces or might produce significant emissions of air pollutants."[2] Accordingly, the source, facility, process or activity in question *must produce or have the capability of producing* "significant emissions or air pollutants."[3] While this authority is undoubtedly broad, it is limited to emissions producers, whether the 'producer' is a source, process, or the like. In the air emissions context, the statute does not provide any authority to go 'outside the fence' or beyond the source to regulate activities that may *indirectly* affect the emission of air pollutants, *e.g.*, environmental dispatch of natural gas units pursuant to Building Block 2, increased penetration of renewable or zero-emission energy under Building Block 3, or increased adoption of energy efficiency measures under Building Block 4.

Colorado state agencies may adopt federal regulations by reference,[4] and this is how the AQCC asserted its authority in promulgating previous rules for existing sources, *e.g.*, municipal solid waste landfills, pursuant to emission guidelines set by EPA under Section 111(d).[5] If AQCC, and by extension CDPHE and APCD, followed that practice with the CO_2 Emission Guidelines, however, the proposed regulations at 40 CFR Subpart UUUU do not provide any 'outside the fence' authority for a regulatory agency that does not separately possess this

[1] Environmental Protection Agency, Proposed Rule: Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units, 40 CFR Part 60, Vol. 79, No. 117, June 18, 2014.
[2] Colo. Rev. Stat. § 25-7-109(1)(a).
[3] *Id.*
[4] Colo. Rev. Stat. § 24-4-103(12.5).
[5] 5 Colo. Code Regs. § 1008 ("The Commission adopted emissions guidelines for existing municipal solid waste landfills, consistent with the required elements of a state plan set forth in 40 CFR Part 60 Subpart Cc. The language adopted complies with the requirements of Subpart Cc and refers to that subpart for applicability provisions and some other matters. However, the rule also refers directly to the substantive provisions of Subpart WWW, the NSPS, which are largely adopted by reference by Subpart Cc. This strategy was developed in discussion with the interested party to make the requirements of the emissions guidelines for existing sources clear").

authority under state law. 40 CFR § 60.5750, as proposed, allows the administrator of a state air quality program to "include existing requirements, programs and measures" in a state Section 111(d) plan. 40 CFR § 60.5740(6) requires *"[a] demonstration that each emission standard* is quantifiable, non-duplicative, permanent, verifiable, and *enforceable with respect to an affected entity*."[6] Read together, an existing program such as an energy efficiency standard or renewable energy standard may be relied upon, but state law must provide an enforcement mechanism. It does not.

The regulations proposed by EPA in the CO_2 Emission Guidelines cannot override existing state law and alter the existing regulatory regime. For example, the allowance for inclusion of existing programs does not grant CDPHE, APCD, and/or the AQCC authority to enforce existing renewable energy portfolio standards (RPS) requirements or energy efficiency requirements. The PUC enforces these requirements under Colorado law, and the proposed rule does not allow CDPHE, APCD, and/or AQCC to seize existing authorities allocated to the PUC. Regulatory reach is limited to regulating sources, categories of sources, facilities, processes or activities "which produce[] or might produce significant emissions of air pollutants."[7] As discussed below, future legislation *could* alter and expand CDPHE and/or AQCC's existing authority, but the status quo limits its enforcement to Building Block 1-oriented activities.

II. PUC Authority and EPA's Building Blocks

The PUC has varying degrees of regulatory authority over investor-owned utilities, cooperative electric associations, and generation and transmission associations (G&Ts). With respect to investor-owned utilities (IOUs), the PUC has ratemaking authority, resource planning authority, and facilities jurisdiction, *i.e.*, approval authority over major construction such as transmission lines, generating facilities, etc.[8] PUC authority over the sole G&T cooperative, Tri-State Generation and Transmission Association, Inc. (Tri-State), is more limited. It lacks ratemaking authority over Tri-State and with regard to resource planning, Tri-State is only required "to file its [IRP] with the Commission as a report rather than filing it for approval."[9] Tri-State is subject to facilities jurisdiction and must obtain a certificate of public convenience and necessity from the PUC prior to moving forward with infrastructure and other projects.[10] Tri-State's member-systems and the other cooperatives may, and have, voted to exempt themselves from PUC regulation pursuant to Colorado law.[11] Therefore, these cooperatives are not subject to the resource planning, rate or facilities jurisdiction of the PUC and, among other things, do not need to file resource plans for approval. Finally, the PUC does not have resource planning or any other regulatory authority over municipal utilities.[12]

Furthermore, Colorado law has enforceable RPS and energy efficiency requirements. However, these regulatory regimes are also fragmented as applied to the different categories of

[6] 79 Fed. Reg. 34,951-52 (June 18, 2014) (emphasis added).
[7] Colo. Rev. Stat. § 25-7-109(1)(a).
[8] Colo. Rev. Stat. § 40-5-101 *et. seq.*
[9] Decision No. C10-0101, Colorado PUC Docket No. 09I-041E, at ¶ 16 (mailed Feb. 4, 2010).
[10] *See, e.g.,* PUC Docket Nos. 09a-324E & 325E (Tri-State application to build a 345 kV transmission line).
[11] Colo. Rev. Stat. § 40-9.5-104.
[12] Colorado Constitution, Art. V, § 35; *Town of Holyoke v. Smith*, 75 Colo. 286 (Colo. 1924); *City of Lamar v. Town of Wiley*, 80 Colo. 18 (Colo. 1926).

utilities in Colorado. With regard to the RPS, investor-owned utilities must achieve an RPS of 30 percent by 2020 on an escalating scale, and their activities are subject to a two percent retail rate impact cap.[13] Tri-State, and cooperatives with more than 100,000 meters, must meet an RPS of 20 percent by 2020.[14] Cooperatives with less than 100,000 meters and municipal utilities must meet an RPS of 10 percent by 2020,[15] subject to a two percent retail rate impact cap[16]; however, municipal utilities may exempt themselves by majority vote.[17] Moreover, while cooperatives and Tri-State merely file compliance reports with the Colorado PUC, investor-owned utilities are subject to fully-litigated proceedings regarding their RPS compliance plans.[18]

When it comes to energy efficiency, Colorado law requires IOUs to meet certain energy efficiency goals established by the PUC by 2018. These goals are "at least five percent of the utility's retail system peak demand measured in megawatts in the base year and at least five percent of the utility's retail energy sales measured in megawatt-hours in the base year. The base year shall be 2006. The goals shall be met in 2018, counting savings in 2018 from DSM measures installed starting in 2006."[19] The operative phrase in the statute enacting energy efficiency requirements is that "[t]he commission shall establish energy savings and peak demand reduction goals to be achieved by an investor-owned electric utility …."[20] Accordingly, the same enforcement fragmentation exists in the energy efficiency context as well, as investor-owned utilities are subject to statutory and administrative demand-side goals but cooperatives, G&Ts and municipal utilities are not.

III. *Ultra Vires* Action

All relevant agencies referenced above have statutorily-defined authorities or abilities implicated by the proposed CO_2 Emission Guidelines. Accordingly, any of these agencies may find themselves put in a position where operating outside delegated powers is a potential (though problematic) course of action. For example, CDPHE, through new AQCC regulations implementing the proposed CO_2 Emission Guidelines, could be positioned as the *de facto* electric resource planner for the state, overriding the PUC's statutory authority and creating an unsanctioned regulatory paradigm that is the inverse of that contemplated in HB 10-1365, the Clean Air-Clean Jobs Act (CACJA), detailed below. In addition to creating issues for regulated entities in the form of a two-step cost recovery process involving two different agencies and regulatory schemes, its puts all agencies at risk of acting outside of their statutory delegation of authority. Any action based on powers not conferred by statute is *ultra vires* and invalid under

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[13] Colo. Rev. Stat. § 40-2-124(1)(c)(I). The CO_2 Emission Guidelines also do not take into account the retail rate impact limitation of Colorado. To the extent the PUC does have enforcement authority over investor-owned utilities, that authority is limited by the two percent retail rate "cap," which may be asserted by a utility to avoid penalties for failing to reach the RPS renewable energy percentage mandate. Colo. Rev. Stat. § § 40-2-124(g)(I)(A).
[14] Colo. Rev. Stat. §§ 40-2-124(1)(c)(V.5) & § 40-2-124(8)(b).
[15] Colo. Rev. Stat. § 40-2-124(1)(c)(V).
[16] Colo. Rev. Stat. § 40-2-124(1)(g).
[17] Colo. Rev. Stat. § 40-2-124(5).
[18] Colo. Rev. Stat. § 40-2-124(8)(g)(III).
[19] Colo. Rev. Stat. § 40-3.2-104(2).
[20] *Id.*

Colorado law.[21] Absent state legislation remedying this issue, there is significant litigation risk with regard to *ultra vires* action.

IV. Need for State Legislation

Enforcement fragmentation poses a two-fold problem for implementation of the proposed CO_2 Emission Guidelines. First, regulatory enforcement authority is bifurcated between the PUC and CDPHE, acting pursuant to AQCC regulations. Building Block 1 activities are within the purview of AQCC and CDPHE, while the PUC can enforce RPS requirements (Building Block 3) and energy efficiency requirements (Building Block 4). Neither agency can order environmental dispatch, although the PUC could potentially use its resource planning authority to work with IOUs to achieve EPA's assumed 70 percent NGCC utilization rate. Colorado law does not provide for a holistic approach allowing for consideration of all Building Blocks in a single proceeding with a single or primary regulator. To be sure, the CACJA provided for an emissions reduction-driven resource planning proceeding with the PUC as the primary regulator and CDPHE in a supporting role.[22] The CACJA is a one-time resource planning and cost recovery statute, however, that does not apply in typical resource planning proceedings before the PUC. Therefore, the CACJA in its current form does not remedy the bifurcated authority issue.

Finally, while CDPHE and AQCC have jurisdiction over all generators to regulate air emissions at the source, *i.e.*, Building Block 1, the PUC's regulatory authority is not universal. Rather, it has varying levels of authority over different types of utilities. This ranges from extensive enforcement authority (investor-owned utilities) to no authority at all (municipal utilities). Given both of these issues, state legislation is necessary to bring enforceable authority over activities relating to all Building Blocks under a single regulatory regime and allow for increased regulatory authority over traditionally non-jurisdictional entities.

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[21] *See, e.g.*, *Bd. of County Commissioners v. Indus. Comm'n*, 650 P.2d 1297, 1300 (Colo. Ct. App. 1982).
[22] Colo. Rev. Stat. § 40-3.2-204(b).

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Illinois Regulatory Authorities

Interaction with Clean Air Act Section 111(d)

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This Paper briefly addresses several questions regarding the authority of the Illinois Environmental Protection Agency (IEPA), the Illinois Commerce Commission (ICC), and the Illinois Power Agency (IPA) to implement EPA's proposed rule addressing carbon dioxide emissions from existing sources under Section 111(d) (CO_2 Emission Guidelines) of the Clean Air Act (CAA).[1] It first analyzes the scope of the IEPA's delegation to implement the CAA, followed by an analysis of the ICC's regulatory authority and the role of the IPA. It also considers whether these agencies may operate outside of their legally delegated authority. Finally, it evaluates the need for legislation and various proposals related to EPA's proposed CO_2 Emission Guidelines.

For nearly two decades, Illinois has pushed an aggressive agenda seeking to develop a competitive, market-driven electricity market. Over the past five years, the competitive energy industry in Illinois has flourished and alternative retail electric suppliers (ARES) now supply roughly 70 percent of the electric load for state's two largest electric utilities, Commonwealth Edison Company (ComEd) and Ameren Illinois (Ameren).[2] The embrace of competitive energy supply, most notably the success of municipal aggregation, has led to a series of divergent and inconsistent efficiency and renewable policies, as well as various practical limitations on renewable development.

As a result, the energy industry in Illinois is governed by a panoply of laws and processes that can be difficult to reconcile with the state's growing list of environmental objectives. Resource planning for Ameren and ComEd is regulated through a joint process between the ICC and IPA. Due to the success of the state's competitive energy policies, much of state's load has shifted to ARES, which are not subject to the same IPA/ICC resource planning process as ComEd and Ameren. Similarly, though the state has a renewable portfolio standard (RPS) and aggressive energy efficiency targets, these policies apply differently to alternatively supplied load versus "eligible retail" load.[3]

I. IEPA Authority and EPA's Building Blocks

As the state's primary environmental regulator, IEPA has authority to supervise the administration and enforcement of environmental laws and regulations.[4] This includes the authority to regulate generators "inside the fence" to the full extent of the law under the Clean Air Act, including promulgation and enforcement of existing source performance standards under Section 111(d).[5] The Illinois Pollution Control Board (IPCB) initiates and adjudicates enforcement measures.[6]

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[1] Environmental Protection Agency, Proposed Rule: Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units, 40 CFR Part 60, Vol. 79, No. 117, June 18, 2014.

[2] According to the ICC's Office of Retail Market Development, as of March 31, 2014, "[m]ore than 70% of the electric usage in Illinois is served by retail electric suppliers." *Available at*: http://www.icc.illinois.gov/ormd/.

[3] An "eligible retail customer" is defined, *inter alia*, as a "those retail customers that purchase power and energy from the electric utility under fixed-price bundled service tariffs, other than those retail customers whose service is declared or deemed competitive under Section 16-113." 220 ILCS 5/16-111.5(a). The PUA further provides that "[t]hose customers that are excluded from the definition of "eligible retail customers" shall not be included in the procurement plan load requirements." Id.

[4] 415 ILCS 5.

[5] 415 ILCS 5/9.1.

[6] 415 ILCS 5/5.

In the air emissions context, Illinois law does not provide IEPA any "outside the fence" authority to regulate activities that may indirectly affect the emission of air pollutants, such as dispatch of natural gas units as contemplated in Building Block 2, to direct increased development of renewable energy under Building Block 3, or to adopt requirements for energy efficiency measures under Building Block 4.

The regulations proposed by EPA in the CO_2 Emission Guidelines do not – and unless adopted as law, cannot – override existing state law. For example, the rule alone does not grant IEPA *legal* authority to enforce existing RPS or energy efficiency targets. Rather, the ICC oversees and implements these areas. The proposed regulations do not allow IEPA to encroach on existing authorities allocated to the ICC and IPA. As discussed below, future legislation could alter and expand IEPA's existing authority, but without such legislation, IEPA's enforcement authority is limited to activities contemplated under Building Block 1.

II. Illinois Commerce Commission Authority

The ICC is the primary agency tasked with regulating public utilities in Illinois. The ICC's authority is embodied in the Illinois Public Utilities Act (PUA). In 1997, in an effort to facilitate "the development of competition for generation services" and "other services currently offered on a tariffed basis," the Illinois legislature overhauled Illinois' public utility industry and restructured it to "unbundle" generation and utility tariffs. As a result, although the ICC has retained jurisdiction over electric distribution services, the ICC no longer regulates generation assets.[7]

The ICC has no authority to implement the CAA or regulate air pollution. However, the ICC has exclusive jurisdiction over the regulation of rates and service of utilities.[8] This includes authority over investor-owned electric and natural gas utilities but not over municipally-owned utilities or gas or electric cooperatives. Nor does it have authority to regulate the wholesale rates of electric utilities, which are set in the PJM marketplace under Federal Energy Regulatory Commission (FERC) jurisdiction.

As discussed below however, the ICC has jurisdiction over the energy efficiency and renewable portfolio targets identified in Building Blocks 3 and 4.

III. Illinois Power Agency Authority

The IPA is responsible for developing electric procurement plans (*i.e.* resource planning) for "eligible retail customers" of the state's largest investor-owned electric utilities (IOU), Ameren and ComEd. These customers include residential and small commercial fixed price customers who have not chosen service from an ARES.

Additionally, the IPA oversees the state's Renewable Energy Resources Fund (RERF), which "shall be used to procure renewable energy resources" with a priority for resources

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[7] *See* 220 ILCS 5/16-108(d), 109.
[8] 220 ILCS 5/9-252; *see Sheffler v. Commonwealth Edison Co.*, 2011 IL LEXIS 1099.

"procured from facilities in Illinois or states that adjoin Illinois."[9] According to the IPA Act, "[t]o the extent available, 75 percent of these resources shall come from wind generation," and by June 1, 2015, 6 percent from photovoltaics and 1 percent from distributed generation. The law does not expressly authorize the IPA to use RERF money to fund energy efficiency or natural gas projects. Moreover, because the RERF can only be used to procure renewable resources for eligible retail customers, the IPA cannot use these funds to procure renewable resources for alternatively supplied customers.[10]

Though the IPA is tasked with creating resource plans, developing recommendations, and conducting procurements pursuant to such plans, the ICC has ultimate authority to approve, modify or deny all aspects of a procurement plan.

IV. ICC, IPA and the EPA's Building Blocks

To implement EPA's Building Blocks, IPA and ICC will face substantial institutional challenges under Illinois' current regulatory regime. Below is a summary of each Building Block.

Building Block 1. Neither the ICC nor IPA has authority to implement or enforce the provisions of the Clean Air Act, nor measures regarding electric generation. Accordingly, neither agency may develop or enforce the emission control measures contemplated in Building Block 1.

Building Block 2. Similarly, because neither the ICC nor the IPA has authority over generation, neither has authority to require environmental dispatch to achieve the 70 percent utilization of gas-fired EGUs as assumed by Building Block 2.

Building Block 3. The Illinois RPS directs procurement plans to include "cost-effective renewable energy resources."[11] Specifically, 10 percent of each utility's eligible retail portfolio shall come from renewable resources by June 1, 2015 and 25 percent by June 1, 2025.[12] And, to the extent available, at least 75 percent shall come from wind and 6 percent from photovoltaics as of June 1, 2015.[13] In 2013, the Illinois legislature added a distributed generation portfolio standard, which requires the IPA to procure 1 percent of eligible load from distributed generation (which may also count toward the RPS).

The RPS targets are not absolute. In particular, renewable purchases are subject to a 2.015 percent rate cap and must fall within a pre-established benchmark.[14] In the event renewable energy procurements exceed the rate cap, they must be curtailed accordingly.[15] The PUA also dictates that renewable purchases must be cost effective: "[i]ncluding cost-effective

[9] 20 ILCS 3855/1-56.
[10] In an attempt to address this issue, the General Assembly recently enacted Public Act 98-0672, which permits the IPA to conduct a one-time "supplemental procurement" for renewable energy credits from new or existing photovoltaics using up to $30 million from the RERF.
[11] 20 ILCS 3855/1-75(c)(1).
[12] *Id.*
[13] *Id.*
[14] *Id* at (C)(2)(E).
[15] 20 ILCS 3855/1-75

renewable resources and demand-response resources in a diverse electricity supply portfolio will reduce long-term direct and indirect costs to consumers."[16] Importantly, the IPA may only procure renewable energy resources "in conjunction with a procurement event" for ComEd and Ameren.[17] With such a high percentage of load shifting to ARES, there have not been consistent annual procurement events for ComEd and Ameren. Consequently, IPA has been unable to procure renewable energy in such years.

Moreover, the RPS does not apply equally to all load across the state. ARES are subject to a separate RPS, which allows them to make "alternative compliance payments," which are deposited into the RERF and are to be used for REC purchases in place of a shortfall in achieving applicable renewable targets.[18] ARES often find it more cost-effective to make payments rather than purchase renewable energy at the statutory level and therefore frequently opt to make payments at the statutorily-defined rate instead. The RPS also does not apply to municipally-owned utilities or electric cooperatives.

Further complicating the landscape is that competitive energy policies have led to enough load volatility that long-term contracting is all but unheard of. Without the certainty of long-term contracts, lenders are hesitant to invest in renewable projects in Illinois. As a result, new or modified legislation will likely be necessary to incentivize investment in renewable projects if the state seeks to advance the objectives in Building Block 3.[19]

Building Block 4. Under Illinois law, energy efficiency programs for Ameren and ComEd are regulated by the ICC through a bifurcated process: (1) expansion of existing utility programs authorized by the Commission pursuant to Section 8-103 of the PUA, or (2) new programs bid into the IPA/ICC procurement process pursuant to an annual request for proposal taken by each utility. The PUA establishes a schedule of incremental energy efficiency savings goals that electric utilities are to achieve. Specifically, it provides that "[e]lectric utilities shall implement cost-effective energy efficiency and demand response measures" to achieve a goal of 2 percent savings from energy efficiency measures on all energy delivered from 2015 forward, and by 0.1 percent each year through demand response measures.[20]

Notwithstanding, the law is clear that the energy efficiency and demand response targets are purely "goals," and therefore are not enforceable measures as contemplated by Building

[16] 220 ILCS 5/16-101A(g).
[17] 20 ILCS 3855/1-56.
[18] According to the Commission's Rules of Practice, "[a]t least 50% of the obligation to procure renewable energy resources must be satisfied by making alternative compliance payments, and the balance of the obligation to procure renewable energy resources may be satisfied by generating electricity using renewable energy resources, purchasing electricity from renewable energy resources, purchasing renewable energy credits from renewable energy resources, or making alternative compliance payments." 83 Ill. Admin. Code Sec. 45.110(e); *see* 220 ILCS 5/16-115D(b)(2).
[19] Senate Bill 103 was introduced to the Senate on January 23, 2014 with the support of nearly all renewable energy advocates. The bill would amend the IPA Act and PUA to require IPA procurement plans to include procurement of RECs sufficient to meet certain RPS requirements. Additionally, utilities and ARES would no longer procure RECs themselves or through compliance payments. Instead, all users of transmission lines would be charged a fee that IPA could use to procure a mix of short and long-term renewable resources. The Senate has yet to vote on the bill. S.B. 103, 98th. Gen Assem. (Ill. 2014).
[20] 220 ILCS 5/8-103.

Block 4.[21] In addition, energy efficiency and demand response measures are subject to a 2.015 percent rate cap and must be proven to be cost-effective.[22]

Furthermore, both the IPA and ICC's energy efficiency authority is limited to ComEd and Ameren, thus, neither agency may develop or enforce energy efficiency measures for customers served by any ARES, other public utility, municipal utility, or electrical cooperative.

V. *Ultra Vires* Action

Any action based on powers not conferred by statute is *ultra vires* and invalid under Illinois law.[23] Each of these agencies has statutorily-defined authorities or abilities implicated by the proposed CO_2 Emission Guidelines. Accordingly, any of one of them may find itself in a position where operating outside delegated powers is a potential course of action. For example, IEPA could try to insert itself into the resource planning process, potentially infringing on either ICC or IPA's statutory role regarding resource planning. Absent state legislation remedying this issue, there is significant litigation risk with regard to an *ultra vires* action.

VI. Legislative Proposals and Need for Additional State Legislation

On March 28, 2014, the Illinois House proposed House Bill 4465 – the Climate Change and Emissions Management Act (CCEMA).[24] Under CCEMA, beginning in 2016, any facility that has direct greenhouse gas emissions (GHG) totaling 1,000,000 metric tons or more would be required to reduce its GHGs by a specified amount. Reductions could be accomplished through emission offsets and performance credits or by making payments to a newly created Climate Change and Emissions Management Fund.

Even if this bill were to become law, many institutional barriers to implementation of EPA's proposed rules would remain as the bill's application is limited to in-state generation facilities which emit less than 1,000,000 metric tons of carbon; it also does not apply to facilities owned by municipalities or electric cooperatives. Furthermore, the bill neglects to address any of the outside-the fence measures contemplated in Building Blocks 3 and 4, implementation of which will remain a significant challenge under the current state regulatory framework.

Despite legislative proposals to date, it is virtually indisputable that new legislation will be necessary for Illinois to comply with EPA's proposed rules, including the adoption of additional enforcement measures under each of the four Building Blocks. The IEPA has existing authority to implement emission reduction measures at the source, *i.e.*, a Building Block 1 "inside the fence" measure. The ICC has traditional authority to evaluate and approve resource plans that take into account environmental objectives, but must also consider affordability and reliability. None of these agencies possess authority to order increased dispatch of natural gas (Building Block 2). Though the ICC and IPA (to some extent) oversee compliance with the

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[21] 220 ILCS 5/8-103; 220 ILCS 5/16-111.5B(a).
[22] 220 ILCS 5/8-103.
[23] *Lewis-Connelly v. Bd. Of Educ.*, 277 Ill. App. 3d 554, 560 (1996), *citing Evans v. Benjamin School Dist. No. 25*, 134 Ill. App. 3d 875, 883 (1985).
[24] H.B. 4465, 98th. Gen Assem. (Ill. 2014), *available at* http://www.ilga.gov/legislation/BillStatus.asp?DocNum=4465&GAID=12&DocTypeID=HB&SessionID=85&GA=98.

state's existing RPS and energy efficiency targets, these targets are subject to cost-effectiveness standards and do not apply equally to all load.

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Kentucky Regulatory Authorities

Interaction with Clean Air Act Section 111(d)

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This Paper briefly addresses four questions regarding the authority of the Kentucky Public Service Commission (PSC) and Energy and Environment Cabinet (EEC) to implement EPA's proposed rule addressing carbon dioxide emissions from existing sources under Section 111(d) (CO_2 Emission Guidelines) of the Clean Air Act (CAA).[1] It first analyzes the scope of the EEC's delegation to implement the CAA, followed by an analysis of the PSC's regulatory authority. It also considers whether there is any ability for the agencies to operate outside of their delegated authority. Finally, it evaluates whether legislation is necessary to implement and enforce any state plan developed pursuant to the proposed CO_2 Emission Guidelines.

I. EEC Authority and EPA's Building Blocks

The EEC has authority under Kentucky state law to supervise the administration and enforcement of environmental laws and regulations.[2] This includes general regulatory authority as well as specific regulatory authority, including promulgation and enforcement of existing source performance standards under Section 111(d).[3] The EEC implements and enforces air quality regulations (through the Department for Environmental Protection (DEP) and its Division for Air Quality (DAQ), which are part of the EEC) pursuant to statutory authority under Ky. Rev. Stat. § 224.10-100(5), which states that the EEC shall "[p]rovide for the prevention, abatement, and control of all water, land, and air pollution, including but not limited to that related to particulates, pesticides, gases, dust, vapors, noise, radiation, odor, nutrients, heated liquid, or other contaminants …." While this authority is broad, it is strictly limited to sources of pollution. In the air emissions context, the statute does not provide any express authority to go 'outside the fence' or beyond the source to regulate activities that may *indirectly* affect the emission of air pollutants, *e.g.*, environmental dispatch of natural gas units pursuant to Building Block 2, increased penetration of renewable or zero-emission energy under Building Block 3, or increased adoption of energy efficiency measures under Building Block 4.

In addition to this lack of 'outside the fence' authority, the EEC has previously addressed regulation of existing sources under Section 111(d). With regard to regulation of emissions from existing municipal solid waste landfills, the EEC simply adopted the federal regulations at 40 CFR Part 60, Subpart Cc.[4] If EEC followed that practice with the CO_2 Emission Guidelines, however, the proposed regulations at 40 CFR Subpart UUUU do not provide any 'outside the fence' authority for a regulatory agency that does not separately possess this authority under state law. 40 CFR § 60.5750 as proposed allows the administrator of a state air quality program, *e.g.*, the EEC, to "include existing requirements, programs and measures" in a state Section 111(d) plan. 40 CFR § 60.5740(6) requires "*[a] demonstration that each emission standard* is quantifiable, non-duplicative, permanent, verifiable, and *enforceable with respect to an affected entity*."[5] Read together, an existing program such as an energy efficiency standard or renewable energy standard may be relied upon, but state law must provide an enforcement mechanism.

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[1] Environmental Protection Agency, Proposed Rule: Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units, 40 CFR Part 60, Vol. 79, No. 117, June 18, 2014.
[2] Ky. Rev. Stat. § 224.10-100.
[3] 401 Ky. Admin. Regs. 61:005.
[4] 401 Ky. Admin. Regs 61:036.
[5] 79 Fed. Reg. 34,951-52 (June 18, 2014) (emphasis added).

The enforceability issue for existing programs is particularly relevant in Kentucky given the existence of the state energy plan put together by Governor Beshear under the auspices of the EEC in 2008. Strategy 1 addresses energy efficiency under the plan, and Strategy 2 addresses renewable energy. Both Strategies, along with Strategy 3 (addressing biofuels reduction), are "part of Kentucky's Renewable Energy and Energy Efficiency Portfolio Standard (REPS) that states that 'by 2025, Kentucky will derive at least 25 percent of its projected energy demand from energy efficiency, renewable energy and biofuels while continuing to produce safe, affordable and abundant food, feed and fiber.'"[6] This is a 'plan,' however, and not a statute with enforceable requirements. It is voluntary and not "permanent, verifiable, and enforceable …" as required by EPA's proposed regulations. The state energy plan does not provide new statutory authority to the EEC beyond its authority to regulate air pollution and emissions at the source.

Finally, the EEC is subject to House Bill 388 passed in 2014 that expressly addresses Section 111(d) and its implications for existing electric generating units (EGUs).[7] Kentucky law requires the EEC to follow specific procedures, consistent with Section 111(d), in determining legally enforceable emission standards and compliance schedules for EGUs.[8] Moreover, the EEC may not submit a state plan to EPA unless it determines emission standards and compliance schedules based upon the methodology prescribed by the Kentucky General Assembly *and* it is prepared in consultation with the PSC to "[e]nsure that the plan minimizes the impacts on current and future industrial, commercial, and residential consumers; and … [d]oes not threaten the affordability of Kentucky's rates or the reliability of electricity service."[9]

In sum, the EEC possess no generic state law authority to go "outside the fence" and develop or enforce emission control measures that go beyond Building Block 1, *i.e.*, at the source improvements. The EEC must further comply with House Bill 388 in developing any state plan.

II. PSC Authority and EPA's Building Blocks

The PSC is part of the EEC in Kentucky. However, the PSC is an independent agency that is only attached to the EEC for administrative purposes and governed by a specific statutory section under Kentucky law. The PSC does not have authority to implement the CAA or regulate air pollution; rather, the PSC has "exclusive jurisdiction over the regulation of rates and service of utilities."[10] This includes without limitation authority over investor-owned electric and natural gas utilities, as well as electric cooperatives. The PSC does not regulate municipal

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[6] Governor Steven L. Beshear, *Intelligent Energy Choices for Kentucky's Future: Kentucky's 7-Point Strategy for Energy Independence*, at 13 (2008), *available at* http://energy.ky.gov/Documents/Final_Energy_Strategy.pdf.
[7] Ky. Rev. Stat. § 224.20-140 *et. seq.*
[8] *See*, *e.g.*, Ky. Rev. Stat. § 224.20-141 ("(1) The best system of emission reduction which has been adequately demonstrated for coal-fired electric generating units subject to the performance standard. Best system of emission reduction shall take into account the cost of: (a) Achieving the emission reduction; (b) Impacting non-air-quality health and the environment; and (c) Maintaining energy requirements needed to serve the load on the electric generating unit; (2) Reductions in emissions of carbon dioxide that can reasonably be achieved through measures undertaken at each coal-fired electric generating unit; and (3) Efficiency and other measures that can be undertaken at each coal-fired electric generating unit to reduce its carbon dioxide emissions without doing the following: (a) Switching from coal to other fuels; (b) Co-firing other fuels with coal; or (c) Limiting the utilization of the electric generating unit.")
[9] Ky. Rev. Stat. § 224.20-145 (1)(b)(1)-(2).
[10] Ky. Rev. Stat. § 278.040(2).

utilities or the Tennessee Valley Authority and its distribution co-operatives. It retains authority to regulate the wholesale rates of municipal utilities serving jurisdictional utilities.[11]

While the PSC has authority over rates, electric generation, and transmission siting, it does not have any authority to order or enforce activities under Building Blocks 2, 3 or 4. As discussed, Kentucky state law contains no enforcement authority for the PSC to order compliance with REPS, for example, or require environmental dispatch to achieve 70 percent utilization of gas-fired EGUs as assumed by the proposed CO_2 Emission Guidelines. Again, because the renewable energy goals and energy efficiency targets are purely aspirational, the PSC has no legal authority to require compliance.

There are two additional issues with PSC jurisdiction and authority. First, legislation that would mandate the goals of the REPS as statutory requirements has failed to pass the Kentucky General Assembly on several occasions. Second, PSC regulations mandate least cost, or "lowest possible cost," resource planning by jurisdictional utilities.[12] This circumscribes the PSC's ability to approve the acquisition of renewable resources or more expensive baseload generation (*e.g.,* new build gas to replace existing coal-fired EGUs). This has significant implications for any activities under Building Blocks 2, 3 and 4 and the state's ability to rely on these measures to reduce CO_2 emissions and meet the CO_2 performance goal prescribed by EPA.

III. *Ultra Vires* Action

Both the PSC and EEC (acting through DEP and DAQ) have discrete and defined authorities implicated by the proposed CO_2 Emission Guidelines. Accordingly, both the PSC and EEC may find themselves put in a position where operating outside delegated powers is a potential (though problematic) course of action. For example, EEC could try to position itself as the *de facto* resource planner for the state, substituting the EEC's judgment for that of the PSC's statutory authority to evaluate and approve the resource plans of jurisdictional utilities.

The Kentucky Attorney General squarely addressed the issue of *ultra vires* agency action in OAG 12-009:

> Since a city cannot make a unilateral expenditure of funds to maintain a waterway outside its boundaries, federal authorities may not compel a city to do so because the action would be ultra vires. "How power shall be distributed by a state among its governmental organs is commonly, if not always, a question for the state itself." *Highland Farms Dairy v. Agnew*, 300 U.S. 608, 612 (1937). It is a state's prerogative to determine the jurisdiction of its political subdivisions. "Unless a statute expressly provides otherwise, the exercise of a police power by a municipality is limited to its territorial boundaries." *Smeltzer v. Messer*, 225 S.W.2d 96, 97 (Ky. 1949). Federal agencies acting under valid authority may compel state agencies to perform actions within their jurisdiction, but they cannot

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[11] *Simpson County Water District v. City of Franklin, Kentucky, Ky.*, 872 S.W.2d 460 (Ky. 1994).

[12] 807 Ky. Admin. Regs. § 5:058(8)(1) ("The plan shall include the utility's resource assessment and acquisition plan for providing an adequate and reliable supply of electricity to meet forecasted electricity requirements *at the lowest possible cost*. The plan shall consider the potential impacts of selected, key uncertainties and shall include assessment of potentially cost-effective resource options available to the utility") (emphasis added).

> compel a state agency to perform an ultra vires action in the absence of statutory authority to do so. We are not aware of any statute or regulation allowing the Army Corps of Engineers to order a municipality to pay the cost of maintaining territory that is not within its borders. Assuming the federal agency has valid authority, it may compel the state political subdivision that contains the waterway within its boundaries to perform the maintenance of the waterway, but it may not compel not state political subdivisions that do not have jurisdiction over the waterway to do so.[13]

The facts at issue in OAG 12-009 differ from this situation but the principles apply here. EPA cannot compel EEC to overtake the resource planning function, or any other function, from the PSC nor can it force (or allow) the PSC to administer the air program in Kentucky. Moreover, EPA cannot compel either EEC or the PSC (or any other agency for that matter) to enforce the REPS because it is not Kentucky state law. Because no agency can enforce the measures contemplated by the REPS, it necessarily follows that these measures cannot be relied upon as part of a state Section 111(d) plan under existing Kentucky law.[14]

IV. Need for State Legislation

State legislation is necessary in Kentucky to allow for enforceable measures under each of the four Building Blocks. The EEC has existing authority to implement emission reduction measures at the source, *i.e.*, a Building Block 1 measure 'inside the fence' of the affected facility. The PSC retains its traditional authority to evaluate and approve resource plans pursuant to a "lowest possible cost" standard. Neither agency possesses authority to order increased dispatch of natural gas (Building Block 2), enforce the renewable targets in the REPS (Building Block 3), or enforce the energy efficiency targets in the REPS (Building Block 4). Accordingly, new legislation providing this authority is necessary to the extent that Kentucky wants to rely on these measures in its state plan. Absent new legislation, any attempt by the EEC or PSC to require gas dispatch, certain levels of renewable energy acquisition, or energy efficiency adoption constitutes ultra vires action bec**a**use they lack statutory authority to do so.

The existence of the state energy plan does not obviate the need for state legislation because it is not law and not enforceable. Furthermore, Kentucky's "joint exercise" statute cannot provide for *new authority* where statutory authority has not been provided to a state agency by the Kentucky General Assembly. Ky. Rev. Stat. § 65.240, entitled "Joint exercise of power by state agencies with other public agencies," provides as follows:

> Any power or powers, privileges or authority exercised or capable of exercise by a public agency of this state may be exercised and enjoyed jointly with any other public agency of this state, and jointly with any public agency of any other state

[13] OAG 12-009, at 3 (issued June 6, 2012).
[14] 79 Fed. Reg. 34,838 (June 18, 2014) ("EPA is proposing to evaluate and approve state plans based on four general criteria: 1) *enforceable measures that reduce EGU CO_2 emissions*; 2) projected achievement of emission performance equivalent to the goals established by the EPA, on a timeline equivalent to that in the emission guidelines; 3) quantifiable and verifiable emission reductions; and 4) a process for biennial reporting on plan implementation, progress toward achieving CO_2 goals, and implementation of corrective actions, if necessary") (emphasis added).

> or of the United States to the extent that the laws of the United States permit such joint exercise or enjoyment.[15]

While the EEC and PSC could enter into an agreement to jointly exercise their respective powers, and House Bill 388 contemplates a cooperative approach, it does not convey new authority that does not exist for either the EEC or PSC under state law. Therefore, state legislation is still necessary even in light of this statute and House Bill 388.

[15] Ky. Rev. Stat. § 65.240(1). The statute further contemplates that "[a]ny two (2) or more public agencies may enter into agreements with one another for joint or cooperative action pursuant to the provisions of KRS 65.210 to 65.300." *Id.* at § 65.240(2).

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Montana Regulatory Authorities

Interaction with Clean Air Act Section 111(d)

This Paper analyzes the authority of the Montana Board of Environmental Review (BER), Montana Department of Environmental Quality (DEQ) and Montana Public Service Commission (PSC) to implement EPA's proposed rule addressing carbon dioxide emissions from existing sources under Section 111(d) of the federal Clean Air Act (CAA). It first analyzes the scope of authority that has been delegated by the Montana Legislature to BER and DEQ, followed by an analysis of the PSC's regulatory authority. Then, it evaluates whether legislation is necessary to implement and enforce any state plan developed pursuant to EPA's proposed rule. We conclude that Montana law does not allow implementation of the EPA's four building block approach, and that BER/DEQ together cannot undertake the four building block carbon resource planning as contemplated by EPA.

I. BER and DEQ Authority

BER and DEQ have complementary roles when it comes to administering and enforcing environmental laws and regulations in Montana. The BER has broad authority to adopt, amend, and repeal rules for the administration, implementation, and enforcement of the Clean Air Act of Montana. More specifically, "[t]he board may establish the limitations of the levels, concentrations, or quantities of emissions of various pollutants from any *source* necessary to prevent, abate, or control air pollution."[1] Pursuant to this authority, the Board has adopted numerous regulations that incorporate federal air quality and emissions standards by reference.[2]

DEQ does not have rulemaking authority; rather, it enforces orders issued by BER and is charged with developing a comprehensive plan to prevent, control or abate air pollution.[3] In addition, DEQ is empowered under the Montana CAA to play a coordinating function, as it is generally required to "advise, consult, contract and cooperate" with various stakeholders, including other state agencies.[4]

While the authority delegated to BER and DEQ is undoubtedly broad, it is strictly limited to sources of air pollution. In the air emissions context, Montana law does not provide any express authority for these entities to go 'outside the fence' or beyond the source to regulate activities that may *indirectly* affect the emission of air pollutants, such as mandating increased penetration of renewable or zero-emission energy under Building Block 3, or requiring increased adoption of energy efficiency measures under Building Block 4.[5] Furthermore, we have not found any precedent where BER or DEQ have directly engaged in 'outside-the-fence' regulatory activities similar to those contemplated under EPA's proposed rule.

II. PSC Authority

The Montana PSC does not have authority to implement the federal CAA or regulate air pollution; rather, the PSC is "invested with full power of supervision, regulation, and control of public utilities . . ."[6] The PSC does not regulate municipal utilities and, with the limited

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[1] 75-2-203, MCA (emphasis added).
[2] *See*, *e.g.*, A.R.M. §§ 17.8.202 & 17.8.302.
[3] 75-2-112(2)(a), MCA.
[4] 75-2-112(2)(j), MCA.
[5] Notably, EPA has assumed that Montana cannot environmentally dispatch natural gas units under Building Block 2 because Montana does not currently have any natural gas combined cycle plants.
[6] 69-3-102, MCA.

exception of the universal system benefits program discussed below, does not regulate cooperatives.[7]

The PSC has general oversight authority for the activities contemplated under Building Blocks 3 and 4. First, the PSC regulates the renewable portfolio standard (RPS) set by the Montana Legislature in the Montana Renewable Power Production and Rural Economic Development Act, which will require public utilities and competitive electricity suppliers to procure at least 15 percent of their annual retail sales of energy from renewable sources beginning in the year 2015, subject to cost caps.[8] The commission's authority also includes the ability to assess penalties when the RPS is not achieved and hear petitions by utilities for relief from the standard.[9] Notably, cooperatives are exempt from the RPS, with larger cooperatives encouraged by statute to implement and enforce an RPS that considers legislative intent.

Second, the PSC is charged with overseeing energy efficiency programs for regulated utilities. Electrical providers across much of Montana are already operating demand-side energy efficiency programs. For NorthWestern Energy, the state's largest utility serving over 300,000 customers, the cost of these programs is recovered through a lost revenue adjustment mechanism or LRAM. Energy efficiency programs also receive funding from a universal system benefits charge imposed on all customers of competitive electricity providers and cooperatives. The PSC typically reviews and approves each regulated utility's plans, while the local cooperative governing board has authority to approve the energy efficiency plan for the respective entity. In addition, while Montana law and the PSC's rules purport to adopt a "least cost" standard, these provisions also require a consideration of environmental and conservation goals.[10]

The PSC's authority has been interpreted narrowly by the courts. In one case, the Montana Supreme Court held that the PSC lacked authority to invalidate a contract between a utility and a city.[11] The Court limited the PSC's ability to invalidate a contract to areas where rates and services were clearly affected: "jurisdiction of the PSC is limited to the regulation of rates and service as provided by the Montana statutes."[12] In another ruling, the Court held that the PSC lacks authority to unilaterally prohibit a utility's corporate reorganization.[13] The idea that the PSC has implied powers was clearly rebutted.[14] Limiting the PSC's authority to express delegations by the legislature has been subsequently upheld.[15] Although none of these cases speak directly to the issue of regulating 'inside' or 'outside' the fence emissions from utilities and other electric generating units, they demonstrate that the PSC's authority is limited to areas of clearly delegated power and authority.

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[7] *Id.*
[8] 69-3-2006, MCA.
[9] 69-3-2004 (10)-69-3-2004 (11) MCA
[10] 69-3-1202(a), MCA; A.R.M. 38.5.2001 & 38.5.2007(1).
[11] *Billings v. Pub. Serv. Comm'n*, 631 P.2d 1295 (Mont. 1981).
[12] *Id*. at 1303.
[13] *Mont. Power Co. v. Pub. Serv. Comm'n*, 671 P.2d 604 (Mont. 1983).
[14] "It is anomalous to suggest that the Legislature granted to the Commission implied power to enjoin a corporate reorganization while requiring the same Commission to go to court in order to collect a $100 fine." *Id*. at 613.
[15] "An administrative agency may not assume jurisdiction without express delegation by the legislature." *Auto Parts of Bozeman v. Emp't Rels. Div. Uninsured Employers' Fund*, 23 P.3d 193, 200 (Mont. 2001).

III. The Need for State Legislation

Although DEQ appears to possess adequate statutory authority to consult, coordinate and contract with other state agencies, state legislation may still be necessary in Montana to effectuate a coordinated and comprehensive set of enforceable measures under Building Blocks 1, 3 and 4. Both BER/DEQ and the PSC have discrete and defined authorities that are implicated by EPA's proposed rules. BER and DEQ have existing authority to implement emission reduction measures at the source, *i.e.*, a Building Block 1 measure 'inside the fence' of the affected facility; but they do not have authority to enforce the state RPS and are not charged with primary oversight of energy efficiency programs, both of which fall within the jurisdiction of the PSC. This is especially noteworthy in light of a discussion paper recently published by DEQ, which presents the following *potential* pathways the state could follow to comply with EPA's proposed rule:

- existing energy generation plus heavy energy efficiency (*i.e.*, a 220% increase over current levels);
- existing energy generation plus Lewis & Clark Plant co-fire;
- existing energy generation plus moderate energy efficiency and heat rate improvement;
- existing energy efficiency plus heavy renewable energy; or
- existing energy generation plus CO_2 sequestration.[16]

Several of these pathways could require more aggressive energy efficiency programs and/or greater renewable energy penetration,[17] which, in turn, might require a more demanding statewide RPS and/or an explicit statutory mandate for expanded energy efficiency programs. If this occurs, legislation would be necessary to comport with EPA's proposed rules. Although these rules (in particular, 40 CFR § 60.5750) allow the administrator of a state air quality program to "include existing requirements, programs and measures" in a state Section 111(d) plan, the rules also require "[a] demonstration that each emission standard is *quantifiable, non-duplicative, permanent, verifiable, and enforceable with respect to an affected entity*."[18] Read together, a program such as an energy efficiency standard or RPS may be relied upon, but state law must set forth enforceable guidelines. In addition, depending upon the pathway chosen by Montana, the existing exemptions from PSC oversight for municipalities and cooperatives may need to be revisited by the Montana legislature.

The use of Building Block 2 as a remedial matter (increasing the capacity factor of combined cycle gas), meanwhile, has no precedent for enforceability under Montana law. While the PSC may approve integrated resource plans for the investor-owned utilities, those plans do not specify a capacity factor for given resources. The BER/DEQ, meanwhile, specifies pollution emission rates under other sections of the CAA, but does not specify resource dispatch protocol, or the like. In the end, to guard from inevitable legal challenges, the Montana legislature will need to pass a statute delegating appropriate CAA remedial powers to the agenc(ies) it deems

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[16] Montana DEQ, *Options for Montana's Energy Future* (2014), *available at* http://governor.mt.gov/Portals/16/docs/111dwhitepaperpathways91914-final.pdf.
[17] With respect to increased renewable energy, DEQ has observed that the "main challenge with building additional renewable energy in Montana is firm transmission access to send that energy out of state." *Id.* at 9.
[18] 79 Fed. Reg. 34,951-52 (June 18, 2014) (emphasis added).

appropriate. Absent such delegation and collaboration between agencies, any attempt to devise an enforceable state plan is legally susceptible to challenge.

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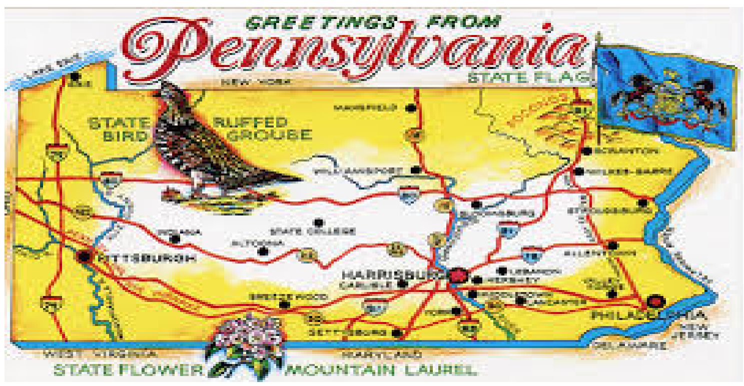

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This Paper explores the authority of the Pennsylvania Department of Environmental Protection (DEP), Pennsylvania Public Utility Commission (PUC) and the Pennsylvania Environmental Quality Board (EQB) to implement and enforce EPA's proposed section 111(d) rules following the enactment of the Pennsylvania Greenhouse Gas Regulation Implementation Act (Implementation Act), which was signed into law by Pennsylvania Governor Tom Corbett on October 22, 2014. First, we summarize the provisions of the Implementation Act, which delegates authority to DEP to draft Pennsylvania's state plan. The ability of the DEP, EQB and PUC to enforce the state plan under existing state law is then considered. Finally, we evaluate whether additional legislation may be necessary to implement and enforce the state plan developed by DEP pursuant to EPA's proposed rule.

I. The Implementation Act

The Implementation Act provides the Pennsylvania General Assembly with an opportunity to approve or reject the state plan that is developed by DEP following a wide-ranging multi-stakeholder process. Although an earlier version of the Implementation Act contemplated that the PUC would play a prominent role in facilitating this process, this language was later deleted, leaving DEP with sole responsibility to develop the state plan.

In developing its plan, DEP is charged with doing all of the following:

- Conduct at least four public hearings; accept and consider all written testimony submitted; and summon and examine witnesses as necessary to discharge its duties under the Implementation Act;
- Consider each of the following factors in developing the plan:
  - Whether to rely on EPA's measures used to calculate Pennsylvania's CO_2 reduction target.
  - Whether to rely on measures that were not considered by EPA in its goal-setting process.
  - Whether Pennsylvania should participate in multistate programs that already exist, or whether a new multistate carbon dioxide reduction program should be created.
  - Whether Pennsylvania should invest in additional energy efficiency programs during the compliance period.
  - When (*not* whether) individual power plants must make reductions.
  - The extent to which any of the following should be included in the state plan:
    - Demand-side energy efficiency programs;
    - Renewable energy standards;
    - Efficiency improvements at existing affected power plants;
    - Co-firing or switching power plants to natural gas;
    - Transmission efficiency improvements;

- Energy storage technologies;
- The retirement or deactivation of existing generation units or facilities;
- The expansion of nuclear power;
- Market-based trading programs;
- Other energy conservation programs; and
- How best to avoid stranded investments in existing affected power plants.

- How to prioritize the components of the state plan based on a least-cost compliance approach to benefit consumers.
- Take into consideration the necessity and value to having a diverse generation fleet to ensure electric reliability in Pennsylvania.

Once DEP has developed the state plan, it will be presented to each chamber of the Pennsylvania General Assembly as a resolution, and each chamber is required to consider the resolution within 20 days. If each chamber adopts the resolution, or if either chamber does not approve the resolution before June 15, 2016, DEP can submit the plan to EPA. However, if either chamber rejects the resolution, DEP is prohibited from submitting the plan to EPA and must modify and resubmit the plan to the General Assembly after divining the reasons for the legislature's disapproval.

Two immediate observations can be made about the institutional roles and process envisioned under the Implementation Act. First, it is striking that a number of the factors DEP is required to consider — including an assessment of a least-cost strategy, reliability impacts, and avoiding stranded investments in modified or retired power plants, among other things — fall squarely within the traditional role and expertise of the PUC. Presumably, the PUC will provide input to DEP through the multi-stakeholder process, but the PUC has not been given a policymaking role under the Implementation Act.

Second, and perhaps an even bigger challenge from a procedural standpoint, the General Assembly appears to envision a process whereby DEP develops and delivers a final plan for legislative consideration. However, given the breadth of DEP's charge in developing the plan, there are a number of potential pathways that could necessitate *additional* legislation, such as participation in a new multi-state program, more aggressive renewable energy and/or energy efficiency standards, a market-based trading program, and so on. This omission is important because EPA's proposed rules (in particular, 40 CFR § 60.5750) allow the administrator of a state air quality program to "include existing requirements, programs and measures" in a state Section 111(d) plan, but the rules also require "[a] demonstration that each emission standard is *quantifiable, non-duplicative, permanent, verifiable, and enforceable with respect to an affected entity*."[1] As discussed below, despite the broad authority that has been delegated to DEP to develop the state plan, potential enforceability gaps still remain under Pennsylvania law.

[1] 79 Fed. Reg. 34,951-52 (June 18, 2014) (emphasis added).

Finally, given the electricity market structure of the Pennsylvania, it remains an open question how owners of plants that are ordered shut down or to curtail (through a carbon-adder in the PJM auction or through some other means) are compensated. For instance, if the DEP determines the best way to meet Pennsylvania's carbon goal is to shutter a coal plant, then how is the owner of that plant compensated? Does that owner have a Takings claim against the state? In a vertically-integrated state, it is easier to socialize the stranded costs, but in a competitive state there is no apparent means to socialize costs related to plants rendered obsolescent by regulation.

II. DEP and EQB Authority

Under the Pennsylvania Air Pollution Control Act, DEP has been delegated general statutory authority to "[i]mplement the provisions of the [federal] Clean Air Act in the Commonwealth." As part of its role, DEP must enforce rules and regulations adopted by the EQB, which (among other things) is generally empowered to "[a]dopt rules and regulations to implement the provisions of the Clean Air Act." While the authority delegated to DEP and EQB is undoubtedly broad, and most certainly encompasses coal unit heat rate improvements under Building Block 1 in EPA's proposed rule, it is strictly limited to sources of air pollution.[2] In the air emissions context, Pennsylvania law does not provide any express authority for these entities to go 'outside the fence' or beyond the source to regulate activities that may *indirectly* affect the emission of air pollutants, *e.g.*, environmental dispatch of natural gas units pursuant to Building Block 2, increased penetration of renewable or zero-emission energy under Building Block 3, or increased adoption of energy efficiency measures under Building Block 4.

III. PUC Authority

The PUC has "general administrative power and authority to regulate all public utilities doing business" within Pennsylvania, which equates to jurisdiction over 11 electric distribution companies.[3] The PUC does not have jurisdiction over municipal power providers or cooperatives.[4] Moreover, Pennsylvania courts have interpreted the power delegated the PUC narrowly. In an early case, the Supreme Court of Pennsylvania stated: "the Commission's authority must either arise from the express words of the statute or by strong and necessary implication therefrom."[5] When the PUC attempted to abrogate a contract between two consenting parties, the Court ruled against the PUC.[6] It held that the PUC's authority to take

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[2] *See*, *e.g.*, Pennsylvania Air Pollution Control Act § 4 (authorizing DEP to issue orders to any person owning or operating an air contamination source if such source is introducing or is likely to introduce air contaminants into the atmosphere in excess of any rate provided for under the Act); *Id.* § 5(a)(1) (authorizing EQB to adopt rules and regulations applicable to all air contamination sources regardless of whether such source is required to be under permit by the Act).

[3] 66 Pa.C.S. § 501(b).

[4] *See Electricity*, Consumer Info, Pennsylvania Public Utility Commission (Oct. 10, 2014) http://www.puc.state.pa.us/consumer_info/electricity.aspx ("Rural electric cooperatives and most utilities owned and operated by cities, boroughs or townships are not regulated by the Commission.").

[5] *Del. River Port Auth. v. Pa. Pub. Util. Com.*, 145 A.2d 172, 174 (Pa. 1958). *See also Day v. Pub. Serv. Com.*, 167 A. 565, 566 (Pa. 1933) ("There is no doubt that the Public Service Commission, being a creature of the legislature, is vested only with those powers conferred by statute "or such as are implied necessarily from a grant of such powers": *Harmony Electric Co. v. Pub. Ser. Com.*, 78 Pa. Superior Ct. 271, 280").

[6] *Pennsylvania Railroad Co. v. Pennsylvania Public Utility Commission*, 7 A.2d 86 (1939).

such a drastic action was "limited to situations in which such action is compelled by the public health, welfare, or safety."[7] The Court provided precedent supporting its contention that the PUC's authority was limited.[8]

The PUC lacks general or specific statutory authority to implement the federal CAA. With the exception of certain compliance requirements under EPA's acid rain program,[9] there is no mention of the federal CAA in the powers and duties delegated to the PUC.[10] That being said, the PUC does have general oversight authority over the activities contemplated under several of EPA's building blocks and, perhaps more importantly, a number of the potential activities that DEP is required to consider pursuant to the Implementation Act. The following examples are not exhaustive. First, the PUC has been required by statute to promulgate rules and provide incentives to utilities that 'uprate' existing coal-fired power plants.[11] Second, a public utility is prohibited from retiring an electric generation unit unless it receives PUC approval.[12] Third, the PUC has been charged with adopting an energy efficiency and conservation program applicable to electric distribution companies, which are now statutorily required reduce electric consumption by retail customers by a minimum of 3 percent.[13] Fourth, and finally, the Alternative Energy Portfolio Standards Act of 2004 requires electric distribution companies and electric generation suppliers to integrate renewable resources in the electricity generation they sell to Pennsylvania customers.[14] The Act specifies renewable generation percentages and eligible technologies, such as photovoltaic.[15] The PUC has general oversight authority under the statute to monitor compliance and assess penalties, and establish regulations governing the verification and tracking of energy efficiency and demand-side management measures.

IV. The Need for Additional State Legislation

Although the Implementation Act establishes a general framework for the *development* of a state plan, additional state legislation may still be necessary in Pennsylvania to ensure a coordinated and comprehensive set of *enforceable* measures. Both BEQ/DEP and the PUC have discrete and defined authorities that are implicated by EPA's proposed rules. BER and DEQ have existing authority to implement emission reduction measures at the source, *i.e.*, a Building Block 1 measure 'inside the fence' of the affected facility; but these entities do not have authority to enforce the Alternative Portfolio Standards Act and are not charged with primary oversight of energy efficiency programs, both of which fall within the jurisdiction of the PUC. Furthermore, depending on the direction DEP takes in developing the plan, more aggressive renewable energy and/or energy efficiency targets may be required, among other measures that implicate the PUC's traditional authority. Finally, the existing exemptions from regulatory

[7] *Id* at 93.
[8] *See Director General of Railroads v. West Penn Railways Co.*, 281 Pa. 309 (1924); *Pittsburgh and Lake Erie Railroad Co. v. Public Service Commission*, 75 Pa. Superior Ct. 282 (1920).
[9] 66 Pa.C.S. § 530.
[10] *See* Pa. C.S. Title 66, Pt. 1, Ch.5 ("Powers and Duties").
[11] 66 Pa.C.S. § 514.
[12] 66 Pa.C.S. § 521.
[13] 66 Pa.C.S. § 2806.1.
[14] 73 P.S. §§1648.1 – 1648.8.
[15] 73 P.S. §1648.3.

oversight for municipalities and cooperatives may need to be revisited by the Pennsylvania General Assembly.

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Appendix B

Entity/Other	Reliability
MISO	14 GW of coal capacity could be at risk for retirement. Many stakeholders have requested that MISO conduct a reliability analysis of the EPA's proposal. In response, in Phase III MISO is currently working to perform reliability assessments with respect to the impacts of the 14 GW of additional retirements identified in this first phase. Additionally MISO fully expects to perform reliability and transmission modeling in future phases as stakeholders target the scenarios most worthy of additional study. *[NOTE: This is from MISO South Region's October 2, 2014 comments to the Louisiana PSC. Phase III is the next modeling phase for MISO, as Phase I and Phase II are completed and have modeled compliance costs]* *** At an October 23, 2014 Board of Directors meeting, MISO announced it had and was continuing to revisit the 14 GW retirement risk figure and that it may be significantly higher: "In six years, there could be a power shortfall of 25 GW, MISO System Planning Committee Chair J. Michael Evans warned. It would take about 70 new natural gas-fired combined-cycle plants to fill that gap, Evans said. "That might suck up well in excess of the available ability of industry to produce turbines, especially when you consider that China and Japan and other people are going to want a few of them too," he said. MISO will report these concerns to the EPA in detail in the comments it will make publicly available next month. … MISO's forecast of 14 GW of retirements is not necessarily final. The grid operator continues to examine the modeling behind that study, MISO President and CEO John Bear said in the meeting. "The initial results were a starting point for MISO's study of the proposed rule," MISO spokesman Andy Schonert said in an email. "We are continuing our work with stakeholders to develop more granular studies about the potential impacts across the footprint, all with the goal of providing our membership additional information and background." *[NOTE: This is from an SNL article and will be updated when MISO issues more formal results]*
SPP	[Reliability Assessment – October 8, 2014] Transmission System Impact Analysis [Part 1 and Part 2] Part 1 of the TSIA was performed using a current 10-year-out summer peak model modified to reflect EPA's projected retirements in the SPP region and surrounding areas. Reactive power limits on remaining generators were increased as necessary to enable a minimally solvable power flow model under system intact conditions and to account for reactive power shortfalls within SPP. Part 2 of the TSIA was performed using an updated 10-year-out summer peak model modified to reflect EPA's projected retirements in the SPP region and surrounding areas. Additionally, new gas-fired and wind generators (see Figure 2) were added within SPP's region and dispatched to offset the majority of the EPA retirements. The generators added to the model were placed in locations based on resource plans developed to support SPP's 10-year transmission planning evaluation. New gas generators, including combined cycle (CC) and combustion turbine (CT), were dispatched at approximately 5,600 MW and new wind generators were dispatched at approximately 300 MW in SPP's model. Wind generation levels at existing plants in SPP were increased by approximately 3000 MW to serve load in SPP and support 2000 MW of transfers from SPP to adjacent areas in Arkansas and Louisiana that would be capacity deficient based on the EPA projected retirements. Additionally, wind resources in MISO were increased to provide 2000 MW of transfers from MISO to these same deficient regions in Arkansas and Louisiana. Both parts of the TSIA identified significant reliability issues. The issues were not mitigated, but actually increased, despite the optimal generation expansion and conservative assumptions used in Part 2 to address EPA retirements. [TSIA Part 1]: ***As a result of the assumed EPA retirements with no resource additions, the SPP network was so severely stressed by large reactive deficiencies that the software used in the analysis was unable to produce meaningful results, which is generally indicative of voltage collapse and blackout conditions.*** In order to enable analytical results, SPP modeled increased reactive limits at remaining generators on the system and was eventually able to achieve analytical results by adding approximately 5,200 MVAR of reactive production to the model during system intact conditions. Because of the arbitrary nature of artificially increasing reactive limits of generators, reliability indicators such as equipment loadings and voltage levels are not accurate and are not presented in this Report. However, this analysis indicates approximately 5,200 MVAR of reactive deficiencies in the SPP footprint during system intact conditions resulting from the modeled EPA generator retirements. Figure 3 shows the reactive power deficiencies within SPP identified by this analysis. The most notable deficiencies were found in Texas and eastern Oklahoma. (emphasis added)

	[TSIA Part 2]: Part 2 of the TSIA utilized the latest optimal generation resource plans available to SPP as well as existing wind resources to mitigate generation shortfalls within SPP. Existing wind generation in SPP and the northern part of MISO were increased to serve shortfalls in the southern part of MISO. An N-1 assessment revealed 38 overloaded elements. ***These overloaded elements were identified in the portions of six states – Arkansas, Kansas, Louisiana, Missouri, Oklahoma, and Texas – that operate within the SPP region. Portions of the system in the Texas panhandle, western Kansas, and northern Arkansas were so severely overloaded that cascading outages and voltage collapse would occur.*** (emphasis added) [Resource Adequacy Analysis]: The Assessment evaluated the impacts of the projected EGU retirements on SPP's reserve margin. SPP has a minimum reserve margin requirement of 13.6% that every SPP member with load serving responsibilities must plan to meet with appropriate generation capacity. In evaluating the impacts of the projected EGU retirements on SPP's reserve margin, SPP utilized current load forecasts, currently planned generator retirements and additions, as well as the retirements projected by the EPA. The Assessment showed that by 2020, SPP's reserve margin would fall to 4.7%, which is 8.9% below our minimum reserve margin requirement. Out of SPP's fourteen load-serving members impacted by the EPA's projected retirements, nine would be deficient in 2020. Furthermore, SPP found that its anticipated reserve margin would fall to -4.0% in 2024, increasing the number of deficient load serving entities to ten. These anticipated reserve margins represent a generation capacity deficiency of approximately 4.6 GW in 2020 and 10.1 GW in 2024. [Conclusion]: The findings in this Assessment make it very clear that new generation and transmission expansion will be necessary to maintain reliability during summer peak conditions if EPA's projected generator retirements occur. Even the scenario that assumes optimal resource expansion using new natural gas fired resources could be problematic during extreme winter load conditions with gas supply and delivery challenges …. ***Unprecedented coordination and cooperation beyond regional planning efforts will be necessary, but may not be timely given significant challenges with interregional planning and necessary system expansion. In addition, broader system assessments of the bulk power system, and natural gas pipeline and storage systems based on environmental constraints will be required.*** *** [EPA Comments – October 9, 2014] [Addressing TSIA Part 1 and Part 2]: The SPP region will experience numerous thermal overloads and low voltage occurrences under both scenarios studied. Results of the first part of the transmission system impact evaluation indicate that if the assumed EGU retirements were to occur absent requisite transmission and generation infrastructure improvements, the power grid would suffer extreme reactive deficiencies (see Figure 3) that would expose it to widespread reliability risks resulting in significant loss of load and violations of NERC reliability standards …. [Addressing limited scope of reliability analysis]: Based on SPP's reliability impact assessment, it is clear that the proposed CPP will impede reliable operation of the electric transmission grid in the SPP region, resulting in violations of NERC's mandatory reliability standards and exposing the power grid to significant interruption or loss of load. SPP has only been able to perform an initial reliability evaluation of steady-state system response during a "normal" future summer peak condition. SPP has not evaluated the impact of the proposed EGU retirements during other potentially critical scenarios, such as drought and polar vortex conditions or times of limited wind resource availability, which have been experienced numerous times within SPP's region in recent history. [Addressing reliability safety valve concept from ISO/RTO Council]: In addition to more time being needed to develop plans for and construction of necessary infrastructure, a "reliability safety valve", as suggested by the ISO/RTO Council prior to release of the proposed CPP, should be incorporated into the final rule. Such an approach would require that state plans include a process to evaluate electric system reliability issues resulting from implementation of the state plan and require mitigation when needed. [Recommendations to EPA]: SPP is providing four recommendations: 1) a series of technical conferences jointly sponsored by the EPA and FERC; 2) completion of a detailed, comprehensive and independent analysis of the impacts the proposed CPP will have on the reliability of the nation's bulk electric system; 3) extension of the proposed schedule for compliance in order for the necessary electric and gas infrastructure to be identified and constructed; and 4) adoption of a "reliability safety valve".
NERC	[General]: According to the EPA's *Regulatory Impact Assessment*, generation capacity would be reduced by between 108 and 134 GW by 2020 (depending on state or regional implementations of Option 1 or 2). The number of estimated retirements identified in the EPA's proposed rule may be conservative if the assumptions prove to be unachievable. Developing suitable replacement generation resources to maintain adequate reserve margin levels may represent a significant reliability challenge, given the constrained time period for implementation. … Pipeline constraints and growing gas and electric interdependency challenges impede the electric industry's ability to obtain needed natural gas services, especially during high-use horizons. … The EPA assumes that the states and industry would rapidly expand energy efficiency savings programs from 22 TWh/year in 2012, to 108 TWh/year in 2020, and reach 380 TWh/year by 2029. With such aggressive energy efficiency expansion, the EPA assumes that energy efficiency will grow faster than electricity demand, with total electricity demand shrinking after 2020. … Constructing the resource additions, as well as the expected transmission enhancements, may represent a significant reliability challenge given the constrained time period for implementation. The implications of this assumption are

	complex. If the EPA-assumed energy efficiency growth rates cannot be attained, additional carbon reduction measures would be required, primarily through reduced fossil-fired generation. [Building Block 2]: The EPA estimates that an additional 49 GW of nameplate coal capacity will retire by 2020 due to the impacts of the proposed CPP. When including the 54 GW of nameplate coal capacity already announced to retire by 2020 (mostly due to MATS), the power industry will need to replace a total of 103 GW of retired coal resources by 2020, largely anticipated to be natural-gas-fired NGCC and CTs. Considering the current and ongoing shift in the resource mix, the EPA proposes to further accelerate the shift, lessening the industry's diversification of fuel sources. As observed during the 2014 polar vortex,19 the relationship between gas-fired generation availability and low temperatures challenges the industry's ability to manage extreme weather conditions—particularly when conditions affect a wide area and less support is available from the interconnection. The polar vortex served as an example of how extended periods of cold temperatures had direct impacts on fuel availability, especially for natural-gas-fired capacity. Higher-than-expected forced outages were observed during the polar vortex, particularly for natural-gas-fired generators, as a result of fuel delivery issues and low temperatures. Overall, extreme weather conditions have the potential to strain BPS reliability and expose risks related to natural-gas-fired generation availability (Figure 3). With greater reliance on natural-gas-fired generation, the resiliency and fuel diversification that is currently built into the system may be degraded, which NERC has highlighted in recent gas-electric interdependency assessments. As an example, current and planned pipeline infrastructures in Arizona and Nevada are inadequate for handling increased natural gas demand due to the CPP. Pipeline capacity in New England is currently constrained, and more pipeline capacity additions will be needed as more baseload coal units retire—this is generally occurring as projected and independent of the CPP. Timing of these investments is also critical as it take three to five years to plan, permit, sign contract capacity, finance, and build additional pipeline capacity, in addition to placing replacement capacity (e.g., NGCC/CT units) in service. The proposed CPP timelines would provide little time to add required pipeline or related resource capacity by 2020. [Building Block 3]: A large penetration of VERs [*i.e.*, variable resources] will also require maintaining a sufficient amount of reactive support and ramping capability. More frequent ramping needed to provide this capability could increase cycling on conventional generation. This could contribute to increased maintenance hours or higher forced outage rates, potentially increasing operating reserve requirements. While storage technologies may help support ramping needs, successful large-scale storage solutions have not yet been commercialized. Nevertheless, storage technologies support the reliability challenges that may be experienced when there is a large penetration of VERs, and their development should be expedited. Based on industry studies and prior NERC assessments,30 as the penetration of variable generation increases, maintaining system reliability can become more challenging. Additional assessments, including interconnection-wide studies, will be needed as the resource plans unfold to better understand the impacts. [Building Block 4]: The EPA appears to overestimate the amount of energy efficiency expected to reduce electricity demand over the compliance time frame. The results of overestimation have implications to electric transmission and generation infrastructure needs. Substantial increases in energy efficiency programs exceed recent trends and projections. Several sources, including but not limited to NERC, EIA, EPRI, and various utilities, have published reports, analysis, and forecasts for energy efficiency that do not align with the CPP's assumed declining demand trend. [Timing]: Because committed transmission projects typically require three to five years to be completed, and often longer for major projects with significant right-of-way needs, NERC is concerned that reliability-related enhancements may not be able to be completed for a 2020 implementation. [Policy Recommendation]: NERC Reliability Standards and Regional Entity criteria must be met at all times to ensure reliable operation and planning of the BPS. Therefore, NERC supports policies developed by the EPA, FERC, the DOE, and state utility regulators that include a "reliability assurance mechanism," such as a reliability back-stop, to preserve BPS reliability and manage emerging and impending risks to the BPS. [Distributed Generation]: The EPA projects that retail electricity prices will increase by $1/MWh to $18/MWh under the CPP55 as a result of a combination of higher natural gas prices and the implementation of new carbon penalties on impacted fossil-fired generators.56 As retail power prices increase, some existing customers may install DERs, when economically advantageous. Depending on the price advantage, the market penetration of DERs could be substantial, creating potential reliability impacts for grid operators that lack visibility and control of these resources. Given that DERs displace grid retail sales, DERs could become a larger grid capacity planning challenge since the grid will remain responsible for being the DER site's back-up power supplier. Reliability issues with large onsets of non-dispatchable resources have already created operational challenges in California, Hawaii, and Germany. *[<u>NOTE</u>: NERC is planning to issue an evaluation of generation and transmission adequacy in April 2015, a follow on reliability assessment reflecting emerging state plans in December 2015, and a third assessment in December 2016 once state plans are developed.]*
ERCOT	ERCOT is currently analyzing a set of environmental regulations (Clean Power Plan, MATS, Cross-State Air Pollution Rule, Regional Haze, Section 316(b) of the Clean Water Act, and proposed revisions to the Ash Disposal rules) and their potential impact on the grid. The focus of the ERCOT study is on grid reliability, but ERCOT's real concern is compliance deadlines and the

	possibility that compliance may be achievable, but at significant cost to the ERCOT system. ERCOT's study will be complete in late November or early December and the results of that study will be incorporated into the PUC's comments to EPA. *[NOTE: This is paraphrased from live testimony from Warren Lasher (Director of System Planning, ERCOT) during the Texas House of Representatives Committee on Environmental Regulation's two-day hearing regarding the proposed rule on September 29-30, 2014]* *** [October 8, 2014 outage illustrates reliability issues under current conditions – ERCOT press release below] 7 p.m., Oct. 8, 2014 – The Electric Reliability Council of Texas (ERCOT) at 6:29 p.m. instructed transmission and distribution service providers to restore electric service following rotating outages in the Lower Rio Grande Valley. While most affected consumers will be returned to service immediately, some providers indicate it could take about an hour to restore service to all affected consumers. Earlier this evening, unplanned power plant outages resulted in electric transmission issues in the Valley, which required action by the grid operator to protect the system in that area. At 4:47 p.m., ERCOT instructed the transmission and distribution providers to reduce system demand by 200 MW to protect the Valley region from the risk of an uncontrolled blackout situation. Additional power also was imported from the power grid in Mexico to help address transmission system issues in the area, and ERCOT is working with the affected generation owners to return their units to service. "We appreciate the patience and help from Valley residents during this situation," said Ken McIntyre, ERCOT vice president, Grid Planning and Operations. "We have been working with transmission providers on projects to improve future electric reliability in the Valley region."
PJM	The Organization of PJM States, Inc. (OPSI) requested PJM Interconnection staff to perform analyses of the potential impacts of U.S. EPA's proposed 111(d) Carbon rule. OPSI's request outlined base case, regional compliance case, regional compliance case scenarios and state-by-state compliance case modeling assumptions. PJM has committed to performing the requested analyses of years 2020, 2025, and 2029 and will augment them with additional sensitivity scenarios focused on generation availability and energy efficiency assumptions. The analyses results will include (by transmission owner zone, state and RTO region): carbon price, carbon emissions rate, Locational Marginal Prices, energy market load payments, percentage of generation by fuel type, and generator net energy market revenue (net of going forward fixed avoidable capital costs). The scope of the initial analyses does not include a transmission planning reliability analysis. PJM will not be identifying NERC transmission planning criteria violations or determining the transmission solutions to address any criteria violations. PJM's modeling will be an energy market analysis. However, PJM intends to use the results of this initial energy market analysis to inform future "at-risk" scenario studies to be performed as part of the PJM Regional Transmission Expansion Planning process. PJM is targeting late October to complete and publish initial results from this analysis and will offer sessions with the states and with stakeholders to review the initial results. PJM will comply with its Operating Agreement provisions pertaining to confidential data.
WECC	An analysis of the Anticipated Planning Reserve margins calculated in the NERC 2014 Long-Term Reliability Assessment shows that in 2020, the beginning of the enforcement period, all four of the WECC subregions have capacity in excess of the 15 percent target. However with the loss of approximately 400 MW (or .53 percent) of capacity in the US portion of the NW subregion, 700 MW (2.97 percent) in the Southwest subregion, 3,500 MW (35 percent) in the Rocky Mountain subregion, or 200 MW (.32 percent) in the US portion of the California/Mexico subregion, the calculated Planning Reserve margin for those subregions could drop below the 15 percent target. … The study results suggest that removing the specified about of coal generation, given the assumptions, would have minimal impact on system frequency response. The minimal change in frequency response is not surprising given that 7,000 MW of incremental retirements represents only about 3.5 percent of the total generation (198,000 MW) in the heavy summer case. Preliminary analysis suggest that the effects would also be minimal in a typical lightly loaded case as the total generation typically being represented is closer to 100,000 MW and still would only result in 7 percent of the generation being displaced …. Interconnection-wide frequency response was not significantly impacted by the specific scenarios analyzed. That is not to say that there are no other reliability issues that should be examined.

Florida PSC Commissioner Eduardo C. Balbis	Reliability is a very real and very significant concern due to Florida's limited interstate transmission capability. Furthermore, Florida's annual cooling degree days is the highest in the continental U.S. Due to these factors, Florida must rely on intrastate generating facilities capable of continuously meeting high levels of demand reliably. Thus, Florida relies heavily on a robust and dispatchable generating fleet. Many of the low carbon/zero carbon technologies the EPA uses to justify the 10 percent Block 3 calculation are intermittent, non-dispatchable, non-base load technologies. For example, in 2013, PV's capacity factor ranged from 13 to 22 pecent *(sic)*. The low capacity factors of many low carbon/zero carbon technologies (excepting nuclear) combined with Florida's need for dispatchable generation means Florida would need to build additional natural gas-fired facilities and related infrastructure for use as stand-by units for reliability purposes. The EPA errs in failing to account for these additional capital expenditures needed to ensure system reliability.
Montana PSC Commissioner Travis Kavulla	Much of the conversation around the EPA's proposed rule has focused on the question of reliability. I will not speculate on the rule's reliability impacts, for the simple reason that no reliability analysis of the EPA's proposed "Best System of Emission Reduction" (BSER) has been conducted for the Western Interconnection, which encompasses 11 states, 2 Canadian provinces, and Mexico's Baja California. Transmission planners at WECC, which is responsible for adopting and enforcing reliability standards for this large slice of the continent, have told state regulators that they cannot accomplish such an analysis by the October comment deadline. Other than WECC, few if any other organizations are in a position to conduct such an analysis. In any case, none have. Many, including the EPA itself, have said that whatever else the proposed regulation accomplishes, it must keep the electric grid operating reliably. I agree. Absent a transmission modeling study that concludes that the BSER's Building Block approach would result in a system as reliable as the one we have today, it is inappropriate to claim that the EPA's BSER is adequately demonstrated. EPA has modeled the outcome of the BSER assumptions using its Integrated Planning Model (IPM). It is important to understand what this model is and is not. The IPM does not and is not intended to model the operations of the transmission grid. Instead, the model focuses on whether in a particular region there are an adequate amount of electric supply resources to meet consumer demand. While this question of resource adequacy is essential to reliability, it is equally necessary to understand whether the resources that exist in a particular region can be delivered to the consumer location of demand. Many of the most critical resources that serve large pockets of consumer demand are located in transmission-congested areas. If this transmission congestion is not incorporated into a model—and, again, IPM does not—then that model cannot reach meaningful conclusions about system reliability. In other words, the way IPM has drawn the regions in its hub-and-spoke representation of the grid do not capture the significant complexity of grid operations within the given region. Additionally, IPM uses an old-world definition of regions that does not accurately represent the present realities of how the transmission grid has been divided into Regional Transmission Organizations (RTOs). Even assuming that the BSER is otherwise a feasible metric for accomplishing the EPA's goal of reducing carbon dioxide emissions, it must be subjected to transmission modeling.
Texas PUC Chair Donna Nelson	According to EPA, more than 40 coal and gas plants will need to retire in Texas. The proposed rule mandates a 52% reduction in coal generation. How will that effect reliability? Texas is in three transmission organizations. It is extremely difficult to try and figure out how to coordinate compliance with this rule. In the Southwest Power Pool's preliminary analysis, its algorithm could not produce results because of reactive deficiencies. And those deficiencies were the worst in Texas, Oklahoma, and Kansas. That means there will be significant loss of load or rolling outages. When SPP measured that impact on generation, its reserve margin would drop to 4.7% by 2020, and by 2024 it would drop to -4%. The current reserve margin in SPP is 13.6%. *[NOTE: This is paraphrased from live remarks during the Texas House of Representatives Committee on Environmental Regulation's two-day hearing regarding the proposed rule on September 29-30, 2014]*
Texas PUC Commissioner Ken Anderson	In determining the BSER for Block 3, EPA uses a capacity factor for Texas wind of between 39% and 41%.6 For reliability purposes, ERCOT assigns wind an 8.7% wind capacity factor which is the estimated availability of wind during summer peak. ERCOT is late in the process of recalculating the effective load-carrying capability (ELCC) of wind and is expected late next month to assign West Texas wind an ELCC of 14.2% and coastal wind and ELCC of 32.9%. Both figures are still substantially below the capacity factor the EPA assigns to Texas wind energy. *[NOTE: The ERCOT Board of Directors is scheduled to discuss and vote on the wind capacity factor assignments above on October 13, 2014]*