EPA's CO_2 Rules and the State Institutional Problem

Legislative and Regulatory Complexities for Existing State Institutions

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Executive Summary

New institutional approaches and state legislation are needed to implement EPA's proposed rule. For a state that wants to use Building Blocks 2, 3 and 4 to meet its carbon budget, the legislature will need to authorize a new unified carbon IRP to implement a fully enforceable state plan. States will need to devise new institutional approaches involving something of a hybrid between an environmental/air regulator and a traditional utility regulatory commission.

An interagency pledge to 'work together' is necessary but not sufficient to comply with the proposed rule. EPA's approval criteria render such a casual approach unworkable. In the absence of state legislation marrying regulatory authority to allow for the collective enforcement of a state plan, states cannot implement all facets of the rule. Cooperation between state agencies is necessary, but not sufficient, to devise an enforceable rule.

State environmental/air regulators only have existing authority to implement a source-based program. A source-based approach under the auspices of the state environmental regulator turns energy policy, with attendant considerations of reliability, cost and other factors, over to a regulatory body that lacks the specific expertise of state PUCs. The generation fleet alone bears the full burden of all CO_2 emission reductions under this approach.

A Building Block 1-only plan is EPA's most potent avenue to force states to shutter carbon-intensive generation. If a state Section 111(d) plan is disapproved, then EPA will most likely impose a Building Block 1-only plan. In turn, a Building Block 1-only plan creates incentives to retire certain carbon-intensive generation units in an effort to preserve others. This, however, creates intrastate rivalries between generators as to what units get shuttered and whose customers bear the cost. An intrastate compensation mechanism will need to be devised to resolve the equities of a Building Block 1-only plan.

An 'assumed authority' approach for air regulators to enforce outside-the-fence reduction measures without state legislation is legally and practically perilous. The idea of a carbon IRP or general carbon planning process driven solely by the environmental/air regulator may at first seem attractive, but carries unsupportable risks for utilities and customers. Most importantly, it obviates the traditional role and expertise of PUCs, which also are the agencies that have the responsibility to determine regulated utility cost increases associated with the carbon IRP.

I. Introduction

In our earlier White Paper, "State Implementation of CO_2 Rules," we discussed the institutional hurdles faced by states in implementing EPA's proposed carbon rule. Briefly, we concluded that:

- states will likely need to pass legislation to make it possible for state air regulators and utility regulators to implement the rule;
- traditional non-state jurisdictional utilities will need to be made part of a unified state "Carbon Integrated Resource Planning (IRP)" process;
- states pursuing a multi-state solution will need to enter into an Interstate Compact to make the rule enforceable, which will likely require congressional approval.

That White Paper of necessity elided some of the more nuanced state institutional questions embedded in the proposed rule. Here, we embark on a follow on series of papers to explore some of those specific state issues.

The Opening Question for this Paper is:

Are new institutional arrangements and state legislation necessary to implement the proposed CO_2 Emission Guidelines?

To date, state-level discussions have focused on whether a particular state can meet the carbon dioxide (CO_2) performance goal under EPA's proposed rule to regulate carbon dioxide emissions (CO_2 Emission Guidelines) under 42 U.S.C. § 7411(d) of the Clean Air Act (Section 111(d)) from electric generating units (EGUs). However, compliance with the CO_2 Emission Guidelines is not a math problem. Focusing on calculations and CO_2 emission rates sidesteps the fundamental issue implicated by EPA's proposed rule, which functions more like an integrated energy policy than a traditional pollution control rule.

The issue is what state institutions can implement and oversee Section 111(d) state plans and under what existing authority. Our conclusion is no state agency or institutional regime allows for implementation of the proposed rule in the absence of new state legislation. In the alternative, a state environmental/air regulator may be able to implement a source-based program alone – meaning that the air regulator could impose a unit-by-unit emission limit; but the capacity, reliability and rate impacts would then be the most severe and the air regulator would have no inherent tools to analyze the effects of its source-based-alone emission limitation.

II. Source-Based Clean Air Act Regulation

Clean Air Act regulation has historically focused on control activities at the source or 'at the stack' of an EGU. Section 111(d) is no different, and the language of the statute requires that performance standards mirror emission reductions that are achievable at each EGU.[1] EPA has recognized this construction in previous Section 111(d) rulemakings.[2]

In setting the CO_2 performance goal for each state under the proposed CO_2 Emission Guidelines, however, EPA has for the first time ventured beyond the fence in calculating state-specific goals. Of the four Building Blocks, three are beyond the fence. To be sure, states are not required to satisfy the assumptions used by EPA in each Building Block. Nevertheless, only Building Block 1, addressing efficiency improvements at coal-fired EGUs, is indicative of traditional Clean Air Act regulation.[3] Further, implementation of the Building Block 1 assumption alone, even if feasible, cannot achieve anywhere near EPA's 30 percent CO_2 reduction by 2030 goal, so other outside-the-fence measures are *de facto* required.

Assuming the legality of the proposed CO_2 Emission Guidelines, the nontraditional nature of the rule in calculating the CO_2 performance goal requires concomitant research into the regulatory institutional arrangements in states. A traditional state-level regulatory approach, with an environmental regulator issuing an emission limit permit or functional equivalent for a source, will no longer suffice, or will only suffice with the most draconian outcomes.

As we see it, states will need to devise new institutional approaches to implementing the proposed

[1] 42 U.S.C. § 7411(d) is titled "[s]tandards of performance for existing sources; remaining useful life of source." 42 U.S.C. § 7411(d). "Existing source" is defined as "any stationary source other than a new source." 42 U.S.C. § 7411(a)(6). A "stationary source" is defined as "any building, structure, facility, or installation which emits or may emit any air pollutant." 42 U.S.C. § 7411(a)(3).

[2] *See, e.g.*, 40 C.F.R. § 60.82 (subjecting sulfuric acid production units to a 4 pounds sulfur dioxide per ton of acid produced emission rate).

[3] The scope of Building Blocks 2, 3 and 4 present significant legal issues and questions of whether EPA has stepped beyond its statutory authority in the CO_2 Emission Guidelines as proposed, but that question is beyond the scope of this White Paper.

rule involving something of a hybrid between an environmental/air regulator and a traditional utility regulatory commission. Legislatively, this becomes something of a challenge, particularly in states with non-PUC[4] jurisdictional utilities (municipal utilities and cooperatives) that historically jealously guard their non-regulated status. Nevertheless, for a state that wants to use Building Blocks 2, 3 and 4 or other outside-the-fence measures to meet its carbon budget, the legislature will need to authorize a new unified carbon IRP to implement a fully enforceable state plan.

III. EPA's Approval Criteria Drive the Institutional Question

A key point on the institutional issue centers on the nature, respectively, of a state implementation plan (SIP) under Clean Air Act Section 110 and a state plan under Section 111(d). EPA states:

> A CAA section 111(d) state plan will differ from a state implementation plan (SIP) for a criteria air pollutant national ambient air quality standard (NAAQS) in several respects, reflecting the significant differences between CAA sections 110 and 111. A CAA section 110 SIP must be designed to meet the NAAQS for a criteria air pollutant for a particular area - not for a source category - within a timeframe specified in the CAA. The NAAQS itself is based on the current body of scientific evidence and, by law, does not reflect consideration of cost. By contrast, a CAA section 111(d) state plan must be designed to achieve a specific level of emission performance that has been established for a particular source category within a timeframe determined by the Administrator and, to some extent, by each state. Moreover, the emission levels for the source category reflect a determination of BSER, which incorporates consideration of cost, technical feasibility and other factors.[5]

The distinction in naming conventions is irrelevant from a state institutional standpoint. First, a state Section 111(d) plan is enforceable in the same way as a SIP:

> Under CAA section 111(d), a state must submit its plan to the EPA for approval, and the EPA must approve the state plan if it is 'satisfactory.' If a state does not submit a plan, or if the EPA does not approve a state's plan, then the EPA must establish a plan for that state. Once a state receives the EPA's approval for its plan, the provisions in the plan become federally enforceable against the entity responsible for noncompliance, in the same manner as the provisions of an approved SIP under CAA section 110.[6]

Second, and more importantly, EPA's approval criteria for state plans, not the document title, are the salient considerations in analyzing the state institutional question analyzed here:

> The 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.[7]

The need for new institutional arrangements arises from these criteria, specifically the first requirement that CO_2 emission reduction measures be enforceable by a regulatory entity. Therefore, whether the plan is classified as a Section 111(d) state plan or a SIP, the requirement that a regulatory entity has authority to enforce the CO_2 reduction measures does not change. Enforceability ultimately dictates whether any state plan is approvable by EPA.

[4] The term "PUC" is used generically throughout this document to encompass the utility regulator in each state.
[5] 79 Fed. Reg. 34,834 (June 18, 2014).
[6] 79 Fed. Reg. 34,844.
[7] 79 Fed. Reg. 34,838.

IV. Existing Institutional Arrangements and the Need for State Enabling Legislation

With enforceability as the guide, the Building Blocks employed by EPA illustrate the conundrum faced by states in implementing the proposed CO_2 Emission Guidelines. States are not required to overhaul the generation fleet to adopt and implement the assumptions used in the four Building Blocks. States do not have to reduce the heat rate of all coal-fired EGUs by six percent or meet the renewable energy penetration and energy efficiency assumptions employed by EPA – assuming they can be met at all. Because each state is ultimately responsible for achievement of its overall CO_2 performance goal (or an aggregated multi-state CO_2 performance goal, where applicable), it is reasonable to expect that many states will seek CO_2 emission reductions through actions represented by each building block. Therefore, given EPA's strict approval criteria for Section 111(d) state plans, the relevant question is what regulator has *existing* authority to enforce measures contained in each building block.

Building Block 1: This building block assumes that coal-fired EGUs can improve their heat rate by six percent. This is indicative of the traditional Clean Air Act regulatory regime, as EGUs are subject to specific emission rate requirements. These emission rate requirements typically fall under the enforcement jurisdiction of the state environmental regulatory agency. This is consistent with how most states enforce National Ambient Air Quality Standards (NAAQS), the Regional Haze Program, and other Clean Air Act regulations.

Building Block 2: This building block assumes a 70 percent capacity utilization rate for combined-cycle gas-fired EGUs. This assumption depends upon dispatch protocols and re-dispatch among affected EGUs. Unlike Building Block 1, this is *not* indicative of the traditional Clean Air Act regulatory regime. Within organized markets, a regional transmission organization (RTO) or independent system operator (ISO) serves as the system operator and controls dispatch. RTOs and ISOs are subject to the jurisdiction of the Federal Energy Regulatory Commission. In vertically-integrated states, dispatch is not specifically regulated by either PUCs or state environmental regulators. Therefore, the regulatory entity implicated by this building block is as uncertain as the precise contents of a state or multi-state Section 111(d) plan structured solely around dispatch protocols.

Building Block 3: This building block involves the calculation of a renewable portfolio standard (RPS) based on the average RPS of states in the same region of the country, and assumes usage of nuclear power plants based on existing and expected nuclear units. Some states have enforceable RPSs while others have voluntary or aspirational goals. In voluntary states, there is no applicable regulatory agency because the RPS is not enforceable.[8] Where an enforceable RPS is in place, the state PUC is the typical regulator and enforcer of the requirement.[9] As to nuclear power usage, this again would be in the regulatory province of a state PUC, assuming the state PUC has enforceable resource planning authority.

Building Block 4: This building block assumes that states can achieve 1.5 percent demand reductions *annually* from energy efficiency measures.[10] Further, EPA provides that "[s]eparate estimates were developed for each year to reflect the fact that energy efficiency programs that are implemented on an ongoing basis would be expected to produce larger cumulative impacts on total annual electricity usage over time."[11] In states with enforceable energy efficiency requirements, the state PUC is generally the relevant regulator. Other states, however, have no enforceable energy efficiency requirements and therefore there is no regulator. Non-profit or for-profit entities may advocate and implement energy efficiency measures in these states, but there is no specific enforcement mechanism against them. If targets are not met, there is no regulatory consequence. Presumably, to use Building Block 4, all distribution

[8] The western states serve as an example of divergent approaches to renewable energy adoption. In the proposed CO_2 Emission Guidelines, all western states are grouped together for purposes of Building Block 3, including California, Colorado, Montana, Nevada, and Washington. The wind, solar, and geothermal resources in each state differ markedly and some states have legislatively mandated RPSs and some do not. California and Colorado's RPS percentage is double that of Arizona, Montana and Washington. Idaho and Wyoming have no RPS. These state laws drive the amount of renewable energy penetration in each respective state along with the amount of resources that are available.

[9] *See, e.g.*, Cal. Pub. Util. Code §§ 399.11-399.32 (governing the California Public Utilities Commission); C.R.S. § 40-2-101 *et seq.* (governing the Colorado Public Utilities Commission); 20 ILCS 3855/1-75(c) (governing the Illinois Power Agency); 220 ILCS 5/16-115D (governing the Illinois Commerce Commission).

[10] 79 Fed. Reg. 34,896.

[11] *Id.*

utilities within a state would need to have an enforceable, auditable and verifiable energy efficiency/demand reduction program. Moreover, in many states there is no state PUC authority over public power (*e.g.*, municipal utilities) and cooperatives (*e.g.*, REAs). Many state RPS (Building Block 3) and energy efficiency (Building Block 4) requirements apply only to traditionally regulated utilities (IOUs) but not to other entities.

This brief exercise illustrates that existing authority to enforce activities from the categories represented by each Building Block is not assembled within one regulator's exclusive jurisdiction. Because a state plan must be enforceable to be approved by EPA, remedying this disconnect to create a regulatory regime capable of enforcing each category is imperative to avoid implementation of a federal plan.

It follows then that state legislation is required to avoid the path of an inevitable federal plan where a state plan as proposed is unenforceable. This is by no means a novel conclusion; indeed, EPA's analysis reaches the same result couched in more equivocal terms. For example, in its Technical Support Document (TSD) entitled State Plan Considerations, EPA provides:

> *[A]n enforceability consideration* is whether an IRP, and related public utility commission orders, must include additional requirements to implement certain actions, beyond denial of rate recovery or a change to utility tariffs if a utility fails to meet specified obligations in the IRP. *If so, this may require state legislation to provide additional authority to state public utility commissions in some states, or confer additional authority to other agencies (e.g., a state environmental agency).*[12]

Accordingly, EPA is clearly contemplating that the authorities provided to state PUCs and/or environmental agencies under existing state law are inadequate to implement key components of a Section 111(d) state plan. As noted above, there are even more pronounced jurisdiction and enforcement issues with regard to cooperatives and municipal utilities. EPA recognizes this in its State Plan Considerations TSD:

> Under a utility-driven portfolio approach, the entire suite of obligations under the plan would be enforceable against the utility company, which would also be an owner and operator of affected EGUs. If there are other affected EGUs in the state that are not owned and operated by a vertically integrated utility, a state plan might need to include other measures that address CO_2 emission performance by these affected EGUs.
>
> A similar approach could be taken by municipally owned utilities or utility cooperatives, which often also engage in an IRP process. However, state public utility commissions (PUCs) often do not regulate these utilities. As a result, implementation of a portfolio approach by these entities would introduce practical enforceability considerations under a state plan.[13]

EPA's "enforceability considerations" and the 'institutional issues,' *i.e.*, lack of existing state authority under one common regulator, are synonymous. While some may just see this problem as requiring agencies to 'work together,' EPA's approval criteria renders such a casual approach unworkable. In the absence of state legislation marrying regulatory authority to allow for the collective enforcement of a state plan, states cannot implement all facets of the rule. Cooperation between state agencies is necessary, but not sufficient, to devise an enforceable rule.

V. Avenues Forward Without Existing State Institutions

States moving forward, or forced to move forward by the timelines of the proposed CO_2 Emission Guidelines, appear to have two options: (1) implementation of a Building Block 1-only plan or (2) a PUC-driven plan that will require imposition of a Building Block 1-only plan on non-jurisdictional entities.

[12] EPA Office of Air and Radiation, *State Plan Considerations – Technical Support Document for Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units*, at 15-16, Docket ID No. EPA-HQ-OAR-2013-0602 (June 2014) (hereinafter State Plan Considerations TSD) (emphasis added), available at http://www2.epa.gov/sites/production/files/2014-06/documents/20140602tsd-state-plan-considerations.pdf.

[13] *State Plan Considerations TSD, at 11-12.*

A. Building Block 1-Only Plan

States could seek to meet their proposed CO_2 performance goals with only a source-based program 'at the stack.' Proceeding in this manner has been part of the dialogue and cited favorably in some circles as stakeholders digest the proposed rule. However, this appears to be driven by an under-appreciation or discounting of the proposed CO_2 Emission Guidelines' non-traditional nature. The proposed rule arises under a seldom-used section of the statute, and EPA relies upon an expansive reading of the scope of its authority under Section 111(d). Therefore, viewing implementation as similar to NAAQS or Regional Haze Program implementation is short-sighted. To be sure, a source-based program that effectively relies solely on Building Block 1 avoids the difficult institutional questions and may obviate the need for state legislation. When the relative ease of such an approach is considered in conjunction with the observations below, however, it becomes clear this is not a viable path.

First, a source-based approach under the auspices of the state environmental regulator turns energy policy, with attendant considerations of reliability, cost and other factors, over to a regulatory body that lacks the specific expertise of PUCs. Further, IOUs that are jurisdictional to a PUC cannot abide a two-step process of carbon-driven planning followed on by cost recovery at the PUC. An IOU will want an integrated process.

Second, the generation fleet alone bears the full burden of all CO_2 emission reductions under this approach. In its State Plan Considerations TSD, EPA describes the rate-based CO_2 emissions limit "pathway" as follows:

> Rate-based emission limits would apply a lb CO_2 /MWh emission limit to affected EGUs. Depending on a state's approach, compliance flexibility could be provided through different mechanisms, such as averaging among affected sources, or the use of tradable credits for avoided CO_2 emissions resulting from end-use energy efficiency and renewable energy measures as discussed below. In the case of the latter approach, such credits could be used by an affected EGU to adjust its CO_2 emission rate when demonstrating compliance with a rate-based emission limit.[14]

The Building Block 1-only approach is a mutated version of this pathway. It relies solely on the emission limits without any system for crediting EGUs for avoided CO_2 emissions. The ability of EGUs to take credit for these avoided emissions is entirely contingent on the legality of EPA's proposed rule, which is outside the scope of this paper. However, assuming that the CO_2 Emission Guidelines are finalized as is and withstand legal scrutiny, the generation fleet would be responsible – standing alone – for meeting the CO_2 performance goal. As noted above, the six percent heat rate improvement assumed in Building Block 1 does not remotely achieve the carbon reductions envisioned by the EPA. Thus, a source-based program would likely result in massive fuel-switching and premature retirements at significant customer costs with potentially perilous reliability implication.

In sum, the Building Block 1-only approach puts states at significant reliability risk and fails to take advantage of potential avenues to alleviate the compliance burden on its necessary baseload generation. Accordingly, this lends itself to the conclusion that states cannot implement the proposed rule in a feasible way without new state legislation creating the necessary institutional arrangements and authorities.

B. Building Block 1-Only Plan for Non-Jurisdictional Generators

A second possible avenue to proceed within existing state regulatory structures is for a PUC to implement and enforce a state Section 111(d) plan against the entities under its jurisdiction. As EPA notes, in many states PUCs do not have jurisdiction over cooperatives or municipal utilities. Under this approach, a state plan would have CO_2 emission reduction measures enforceable against jurisdictional utilities and provide that the state could not enforce the proposed measures against municipal utilities and cooperative for want of PUC jurisdiction. This would result in an outcome well-known to those familiar with the Regional Haze Program, where EPA approves and partially disapproves the state plan. EPA possesses similar authority under the Section 111(d) implementing regulations, and may approve or disapprove of all or a portion of a state plan if the state fails to meet deadlines or does not comply with the regulations.[15] EPA may institute its own emission standards where those proposed by the state are

[14] *State Plan Considerations TSD, at 7.*

[15] 40 C.F.R. § 60.27(c).

noncompliant with Section 111(d) and its implementing regulations.[16]

If the portion of the state plan addressing cooperatives and municipal utilities would be disapproved, EPA would determine the legally enforceable emission standards and compliance schedules against these entities. EPA could attempt to mandate a wide variety of measures against the non-jurisdictional entities. However, because of the institutional issues discussed above EPA, as well as the agency's questionable legal authority, EPA would likely avoid measures aimed at Building Blocks 2, 3 and 4 because any such measures would put state regulators in a position where federal law mandates *ultra vires* actions. To avoid this complicated scenario, EPA would likely impose a Building Block 1-only program consistent with traditional Clean Air Act regulation as the path of least resistance. At this point, of course, we are back to the unacceptable concerns raised in the previous section because the unmitigated compliance burden falls on baseload EGUs. Accordingly, while a PUC-driven approach that sidesteps regulation of non-jurisdictional utilities and entities is facially appealing for purported ease of implementation, it suffers from the same practical implementation problems outlined in the previous section. Again, this avenue fails to provide a non-legislative solution to the state institutional problem.

Most importantly, any draconian and unachievable emission standards and compliance schedules promulgated by EPA (assuming they could withstand legal scrutiny) would allow the agency to achieve indirectly what it cannot directly, *i.e.,* fuel switching by forcing states to horse trade carbon-intensive units in an effort to salvage at least some low-cost energy options for state residents and businesses. This creates further institutional problems, however. A state will have strong incentives to "settle" a Building Block 1-only plan by achieving rate reductions through retirement of a single unit. But then the question for the state becomes: Which unit? And once that is decided, the equities among generation owners and the impacts on ratepayers must be worked out. This will probably require some sort of compensation mechanism within the state (or, for that matter, multi-state) carbon generation planning process.[17]

Furthermore, the Building Block 1-only plan against non-jurisdictional utilities will likely have the most far-reaching effects on costs and reliability given the general smaller scale and coal-dependency of many municipal and cooperative utilities. Because municipal and cooperative utilities are for the most part smaller in size, and at the same time rely on fewer generation sources, the rate and reliability effects of a plan requiring the municipal utility or cooperative to turn over its general fleet wholesale would have a significant deleterious effect.

C. <u>Environmental Regulators "Outside the Fence"</u>

State environmental and/or air regulators could attempt to rely on a broad delegation of authority to implement the Clean Air Act and move forward with a rulemaking for the CO_2 Emission Guidelines. This 'assumed authority' approach is analogous to New York's tactic with the Regional Greenhouse Gas Initiative (RGGI). Rather than passing state legislation implementing the RGGI Model Rule like all other RGGI states, New York went the 'assumed authority' route and bypassed the legislature. The New York Department of Environmental Conservation (NYDEC) promulgated regulations based upon its existing authority. To be sure, this resulted in litigation, but the merits of the claims were never considered because the claims were time-barred.[18] Notably, every other state in the RGGI did pass implementing legislation.

Beyond the inevitable litigation associated with this approach, there are several other key considerations. First, any attempt by a state environmental regulator to implement the full scope of the proposed CO2 Emission Guidelines, *i.e.*, enforcement of dispatch protocols, renewable energy mandates, and energy efficiency requirements, based upon existing or broad Clean Air Act authority goes far beyond the actions of the NYDEC with RGGI.

[16] 40 C.F.R. § 60.27(d)-(e).

[17] Take a simple scenario of state A with five carbon-intensive generation units, with five different owners, which under a rate-based Building Block 1-only imposed plan would be forced to close all of those units because none could meet the rate-based target. One path to compliance would be for the state to "settle" the plan with EPA by agreeing to retire one of those five units. But in this hypothetical, the burden for carbon compliance would fall on a single generation owner, who would likely demand some compensation (and in turn rate relief for customers) from the remaining four units. To our knowledge, such a compensation mechanism and authority does not currently exist under state laws. An RTO could presumably devise some sort of a tax system to compensate a sacrificed generation unit, but that authority is not inherent in RTOs.

[18] *See Thrun v. Cuomo*, 112 A.D.3d 1038 (N.Y. App. Div. Dec. 5, 2013).

Second, and more importantly for purposes of this paper, any 'assumed' outside-the-fence authority under state law for the state environmental regulator gives rise to multiple prudential problems. The most fundamental issue is the creation of a two-step resource planning and cost recovery process for utilities. Under this scenario, the carbon IRP, discussed at length in our initial White Paper, is evaluated and ultimately approved by the state environmental regulator. For utilities, however, this is not the final or even most important approval from a business standpoint. Rather, following approval of certain actions under the carbon IRP by the state environmental regulator, *e.g.*, acquisition of 250 MW of solar resources and implementation of an energy efficiency program to achieve the 1.5% annual target assumed under Building Block 4, the utility then has to go before the PUC to obtain cost recovery for these actions, as well as address reliability issues. This is the case because it is unquestionable that state environmental regulators do not have authority to approve cost recovery or evaluate and address reliability issues.

As a practical matter, *ex post facto* cost recovery injects a significant amount of new risk into the regulatory equation for utilities. A wide variety of expenditures could be ordered for carbon planning purposes by the state environmental regulator where the state environmental regulator has unlimited authority to implement the proposed CO_2 Emission Guidelines. These costs would go far beyond the costs associated with retrofits or controls at existing EGUs to include costs associated with unit retirements and new gas-fired, renewable, nuclear, and even next generation coal resource development and/or acquisitions. In addition, the state environmental regulator could order utilities to undertake expansive, expensive energy efficiency programs. Notwithstanding that environmental regulators lack meaningful experience with regard to this system-wide resource planning, they would have authority to order these actions with attendant costs in, quite literally, the billions of dollars for any given state.

As discussed, no state environmental regulator has authority to approve cost recovery. This function is solely the province of PUCs, which would be put in the position of evaluating cost recovery for actions already ordered by a sister agency for carbon planning purposes. To deny cost recovery, the PUC would have to deem imprudent the carbon reduction measures and associated activities blessed by the state environmental or air regulator. This effectively turns the PUC's authority into a mere review of already-approved measures. Moreover, if a PUC has its hands tied on cost recovery, which it would under this scenario and regulatory approach, it is more likely to nick the utility on operation and maintenance costs, return on equity, and other areas where the PUC would still have regulatory authority in rate proceedings.

Utilities will not abide this increased risk, and customers cannot tolerate this regulatory disconnect given the risks associated with state environmental regulators doing resource planning with no background on reliability issues and other integral energy policy issues.

Concerns with such sweeping state environmental agency authority are not limited to traditionally regulated jurisdictional utilities. Non-jurisdictional cooperatives and municipal utilities will also have reliability issues and passed-through costs to internalize, and therefore these entities also may be hostile to an environmental/air regulator-driven carbon IRP. In fact, these smaller non-jurisdictional utilities that lack scale will have a special need to socialize the substantial new capital costs across a wider swath of customers — and will seek "universal service"-like support to cushion rate shock.

For both types of entities, the inevitable result here is the need for new state-level institutional responses, *i.e.*, new state legislation. The idea of a carbon IRP or general carbon planning process driven solely by the environmental/air regulator may at first seem attractive, but even a basic analysis reveals objectionable and insupportable pitfalls and risks to both regulated entities and customers. It obviates the traditional role and expertise of PUCs, as these agencies are completely usurped by state environmental regulators. Therefore, this is not a potential path forward, and again the conclusion is that any state plan developed pursuant to the proposed CO_2 Emission Guidelines cannot be implemented in the absence of state legislation.

VI. Conclusion

Analysis of each non-legislative avenue forward reveals fatal flaws and eventually supports the hypothesis of this paper: Existing state institutional arrangements do not allow for implementation of the proposed CO_2 Emission Guidelines and state legislation is required to do so. Without state enabling legislation, states cannot implement the rule in a way that avoids severe cost consequences to customers and negative reliability impacts to its electric system.

The process for determining the appropriate institutional response and the scope of state legislation that will be necessary differs from state to state. However, given the ubiquitous nature of the state institutional problem created by the scope and structure of the proposed CO_2 Emission Guidelines, the process should begin now to see if states can even design a regulatory structure that allows for implementation of the rule. Without these new structures, states simply cannot move forward with implementation of the proposed rule.

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