Issue Brief: The Electricity System and Implications for Federal Carbon Pollution Standards

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Executive Summary

The U.S. Environmental Protection Agency is currently developing regulations for carbon pollution from existing power plants under Section 111(d) of the Clean Air Act (CAA). [1] As state environmental agencies develop plans in response to EPA guidelines, coordination with state and regional electricity system regulators will be important. While the language of Section 111(d) contemplates state programs, electricity flows across state lines, and in large parts of the country it is managed through multi-state electricity markets that do not align with state borders.

This paper provides a brief primer on the electricity system and the role played by different entities in its operation and oversight, and identifies key issues that will be relevant for states to consider as they develop plans under Section 111(d).

The paper covers three topics:

- ***Principles of Electricity Supply***. Most electricity consumers in the U.S. are connected to a multi-state electric grid. Because electricity cannot be stored, the electricity system must be kept balanced in real time, and this frequently requires drawing power from generators in multiple states. Interstate electricity flows and resource availability will be important considerations in the development of Section 111(d) compliance plans.
- ***Resource Adequacy Planning.*** Many local, state, and regional entities coordinate to ensure power reliability. As environmental regulators work to design and implement Section 111(d) compliance plans, potential impacts of those plans on electric supply will be reviewed by planners, regulators, and stakeholders. Integration and alignment with existing processes for maintaining resource adequacy will be important during Section 111(d) planning.
- ***Scheduling, System Control, and Dispatch.*** Electricity markets already incorporate many environmental costs through established operating rules and practices. Environmental regulators may want to consider strategies, such as multi-state agreements, that take advantage of these existing tools. Understanding how different Section 111(d) strategies might affect electricity markets can help environmental regulators optimize environmental performance and cost-effectiveness.

The introduction of Section 111(d) standards will require collaboration and planning, but many of the regulatory and market processes that could underpin a sound approach to carbon pollution reduction policies can already be found in practice.

[1] President Barack Obama, Presidential Memorandum – Power Sector Carbon Pollution Standards (June 25, 2013), http://www.whitehouse.gov/the-press-office/2013/06/25/presidential-memorandum-power-sector-carbon-pollution-standards.

1. Introduction

Over the past 125 years the U.S. power grid has grown across physical and political boundaries to bring electricity from power plants to customers reliably and economically. Spanning roughly 600,000 miles of wires and 18,000 generating units, and serving hundreds of millions of people, the system is a complex and dynamic organism. It is overseen by many organizations whose roles vary from city to city and state to state, each with a designated role in overseeing planning and operations.

To the outside observer, the operations of the electricity system are mainly visible when it fails. That blackouts happen so infrequently is the result of complex planning and operational processes that address potential issues over time spans ranging from decades to milliseconds. System planners have the ability to adjust their resource plans and market rules to take into account aging infrastructure, new technologies, public policies, and other factors.

Environmental standards are commonplace. Every electricity planning area in the country has its own energy mix and its own strategy for complying with air, water, and other regulations. Taken together, the key players in the electric sector have significant experience incorporating air quality targets, emission performance standards, emission caps, and other environmental policy inputs into electricity planning.

2. Principles of Electricity Supply

The inability to store electricity cost-effectively and at large scale creates a need to balance the electricity system in real-time. Grid operators must match supply to ever-changing demand, often covering multiple states at once. Several principles of electricity supply will be important in considering potential Section 111(d) compliance strategies.

Reliability

Reliability is a critical priority for every electricity system operator, and is measured in two ways. First is adequacy: the system needs to have adequate generating capacity to meet the needs of consumers at all times. Second is security, the ability of the system to withstand sudden disturbances. Reliability is an essential element of any planning strategy and is a prerequisite to success when it comes to changes in electricity system policies.

Extensive Interstate Trade

As a result of ever-changing consumption, electricity flows where it is needed. One minute, the output from a nuclear power plant and a coal-fired plant in Pennsylvania may commingle and power the streetlights of Scranton. The next minute, as people wake up and a factory begins operations, a natural gas-fired plant across the river in New Jersey may be called to join the nuclear and coal generators: three generators, producing electricity at different emission rates, from two different states, serving a single market.

As this simple example illustrates, the electricity consumed in a given state may or may not be generated in that state. Cross-state electricity flows are inevitable on the present-day electricity system since every state's electric grid is connected to one or more neighboring states, and every state (except Hawaii) trades electricity in some fashion with its neighbors.[2] As a result, there is no practical way to determine where the output from a given power plant is "flowing." To compound the issue, since electricity market boundaries do not align with state boundaries, market operators in one part of a state may be exporting electricity at the same time as their counterparts in another part of the state are importing electricity.

This dynamic creates challenges—and opportunities for efficient interstate emission reduction strategies—as states develop plans in response to EPA guidelines under Section 111(d). Additional renewable generation in one state could reduce fossil generation in another state. Similarly, constraints on a coal plant in one state could result in increased emissions from a natural gas plant in another state. Multi-state approaches to Section 111(d) compliance could take advantage of interstate electricity flows to achieve more cost-effective reductions.

Diverse Supplier Base

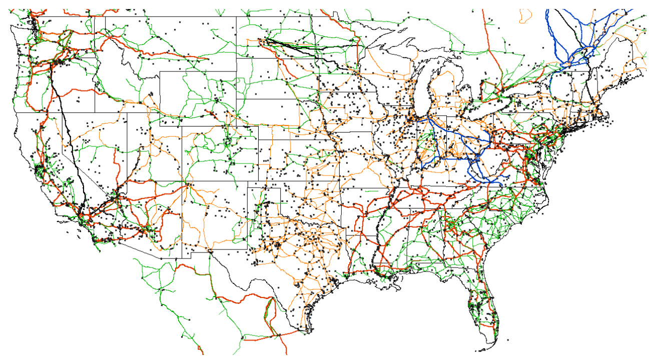

Figure 1: U.S. Bulk Power System (Source: Ventyx Velocity Suite)

Like many commodities, electricity is bought and sold on both wholesale and retail markets. Wholesale electricity is also referred to as "bulk power," and the "bulk power system" describes the infrastructure and operations to generate, transmit, and sell electricity to distribution companies. In this system, transmission lines stretch thousands of miles, linking multiple power plants to customers (see Figure 1). Market operators monitor activity on the grid to make sure that output from those plants is perfectly synchronized with the electricity being used. All of these available resources—including wind farms and coal plants, energy efficiency and demand response, grid-connected storage and other technologies—affect supply and demand on the bulk power market. The bulk power system is owned, operated, and overseen by thousands of companies, government agencies, cooperatives, non-profits, and other entities, which are described in sections 3 and 4 below. All of these entities will be important to consider in the context of Section 111(d) compliance strategies because their combined actions shape power sector emissions at any given moment.

[2] Three states offer slight variations on the rule of interstate electricity markets: California, New York, and Texas. Electricity markets in these states are managed, prices are set, and electricity supply and demand are balanced entirely within state borders. The existence of these single-state electricity markets may make it easier to evaluate the individual state implications under Section 111(d). However, interstate electricity trade remains a factor: California imports, on balance, roughly one-third of its electricity from neighboring states, and New York imports about seven percent of its sales, while Texas' trade is flat. Since these figures reflect net yearly trade, actual cumulative electricity flows to and from these states across state and international borders is, in most years, considerably higher.

No Storage

On a multi-year time scale, electricity resembles many commodities. Demand forecasts guide capital investments, as market players seek to match production capacity with forecasted consumption. This exercise, while far from simple, is carried out through resource adequacy assessment and planning, discussed in section 3.

Over the short run, electricity is unique among commodities: there is no affordable, efficient way to store it in large quantities. Corn can be put in a silo, oil in a storage tank, natural gas in a salt cavern. With the benefit of storage, supply and demand for those goods must only match over months or years. For electricity, supply and demand must match instantaneously. The total electrons flowing into the wires from generators must equal the total electrons flowing out of the socket. This requires dynamic and reactive tools to operate the system in real time. Real-time system operations are discussed in section 4.

3. Resource Adequacy Planning

Planning for "resource adequacy" in each state helps ensure that energy and capacity resources will be adequate to meet forecasted energy consumption and peak demand. Any time a policy shift changes the operating constraints for generators, many entities will collaborate to assess the impact on resource adequacy.

A range of entities—from federal and state regulators, to state energy offices, transmission owners, power generators, and electric utilities—will need to work together with state regulators and with EPA to assess how Section 111(d) compliance strategies could affect the electricity system's ability to meet reliability standards. For example, if a company decides to reduce emissions by shifting generation away from higher emitting units and towards lower emitting units, or by retiring a unit and investing in wind resources, there will be a need to evaluate whether the remaining resources will be sufficient to meet demand.

FERC and NERC

At the federal level, the Federal Energy Regulatory Commission (FERC) is responsible for ensuring the safety and reliability of the nation's electricity system and for regulating interstate trade of electricity. As such, it defines operating standards for multi-state electricity markets. It works to promote competition in the electric sector, ensure grid security and reliability, and ensure that planners fulfill public policy objectives.

FERC's role is primarily that of a "guiding hand" for the power sector. Generally speaking, it does not have direct administrative authority over system operations, planning, or investment. It may issue regulations and orders, or require market participants to file plans to explain any changes in their operating plans. It also regulates interstate sales of electricity and pricing of transmission in the bulk power market.

In the context of Section 111(d), FERC can be expected to work with state and regional entities to ensure a smooth transition as they work to achieve compliance with the guidance issued by EPA. If FERC foresees potential issues, it may hold hearings, technical conferences, or other meetings to hear from experts before deciding whether a change to FERC regulations might be necessary.[3] It may also issue guidelines that outline FERC's role in evaluating compliance plans.

For example, in the past FERC has issued statements to help stakeholders identify the types of market reforms that would require tariff revisions—and trigger a need for FERC approval—versus those that would not require tariff revisions.[4] To the extent that compliance plans involve changes to rates and tariffs, FERC's role, as outlined in Section 205 of the Federal Power Act, is largely "passive and reactive," unless it determines that proposed rate and tariff revisions fail the basic test of being just and reasonable.[5]

FERC has appointed the North American Electric Reliability Council (NERC)[6] to oversee reliability standard-setting and enforcement. Together, FERC and NERC will play an important role to ensure that state Section 111(d) plans maintain grid reliability and integrate well with electricity markets.

Integrated Resource Planning

Many regulated utilities prepare Integrated Resource Plans (IRPs) to help utility commissions understand and evaluate alternative resource portfolios. More than 40 state utility commissions require IRPs or similar analyses and use them to develop a long-range plan for the electricity system that takes into account factors such as public policies, projections of future fuel prices, and operating costs.[7] There is wide variability in states' approaches to the IRP process. While some states have minimal requirements for what plans must include, others require that plans consider all resource types (e.g., efficiency, renewables, nuclear, coal) and include extensive analysis of current and potential environmental costs. In Colorado, for example, goals to reduce air pollution have played a central role in resource planning, and their IRPs could serve as a model for other states.[8]

[3] FERC regularly holds technical conferences to learn from experts and lead dialogues around emerging issues. For example, in February 2014 the Commission announced an upcoming conference on protecting critical infrastructure: FERC, Notice of Technical Conference, http://www.ferc.gov/CalendarFiles/20140227165846-RM13-5-000TC.pdf.

[4] As an example, in 2008 FERC issued a set of guiding principles to transmission system planners who were working on improving their approaches to managing interconnections. *See* FERC News Release, FERC Offers Guidance on RTO, ISO Interconnection Queue Process Improvements, http://www.ferc.gov/media/news-releases/2008/2008-1/03-20-08-E-27.asp. In 2012, FERC issued a statement describing how it would work with EPA to guide the agency's implementation of the Mercury and Air Toxics Standards. FERC, Policy Statement on Commission's Role in EPA's Mercury and Air Toxics Standard, https://www.ferc.gov/whats-new/comm-meet/2012/051712/E-5.pdf.

[5] This principle of review has been clarified in various court decisions. *See, e.g.*, footnote on page 3 of a recent FERC filing by ISO New England. ISO New England Inc. and New England Power Pool Filing on Regulation Market Changes, http://iso-ne.com/regulatory/ferc/filings/2014/mar/er14-1537-000_3-20-2014_reg_mkt_chges.pdf.

[6] NERC is an international not-for-profit regulatory authority whose mission is to ensure the reliability of the bulk power system in the continental United States, Canada, and the northern portion of Baja California, Mexico.

[7] The benefits of IRPs have been outlined in a joint report by RAP and Synapse entitled "Best Practices in Electric Utility Integrated Resource Planning", www.raponline.org/document/download/id/6608.

[8] Colorado's state legislature passed the Clean Air Clean Jobs Act, signed on April 19, 2010, which required the state's rate-regulated utilities to develop plans for reducing air pollutant emissions from coal-fired power plants equaling either 900 MW capacity or 50 percent of their coal fleet. Clean Air – Clean Jobs Act, 2010 Colo. Sess. Laws 466.

State Public Utility Commissions

State public utility commissions (PUCs) oversee the rates and services of retail electricity providers, and may regulate investment in power plants, transmission lines, and distribution networks. Since electric generators are the expected compliance entity under Section 111(d), the key question regarding PUCs is the role they will play in regulating or influencing the investment decisions of generating companies.

From state to state, PUCs will take different approaches due to policy, political, and regulatory differences. This process varies depending on the state's level of market regulation.[9] In fully regulated states, utilities are typically vertically-integrated, owning generation, transmission, and distribution. Customers have only one choice of electricity provider, and the same company provides the service and the supply. In restructured—sometimes called "deregulated"—markets, customers may have retail choice, with the option to buy electricity from a number of different power suppliers. In restructured markets, electricity distribution companies are often restricted from owning power plants. Most of the fully regulated states can be found in the West and the Southeast, while many states in the Northeast and Midwest have undergone restructuring.

PUCs are mandated by state statutes to ensure electricity rates are just and reasonable, and will act within their authority to examine regulated utilities' added costs to secure emission reductions within that framework. A PUC might support a regulatory filing that proposes investments in demand-side energy efficiency, for example, because of the cost savings such investments provide for consumers. PUCs will also consider how Section 111(d) compliance affects resource adequacy. For example, if a vertically integrated utility proposes to shut down a generating unit to reduce emissions, the PUC will work to preserve reliability by evaluating the availability of other generating resources.

Regulated utilities file plans with their PUCs that detail the retail rates they estimate are necessary in order to cover both fixed and variable costs. These costs might include, for example, capital expenditures for power plant construction or retrofits, fuel costs, transmission line upgrades, utility pole replacement programs, emission allowance costs, customer billing software, and so on. In regulated states, therefore, utilities could gain assurance in advance that projected Section 111(d) compliance costs could be recouped.

For regulated utilities that do not also own generation, PUCs have less control over capital investments. Although commissions review and approve retail tariffs, transmission and distribution costs, and other spending categories, they allow the market to control the resource mix and typically do not regulate investment in generators. Under Section 111(d), any additional costs incurred by generators would likely show up in wholesale power prices. Utilities would then have to incorporate their adjusted energy procurement costs into the plans they file with their PUCs. Since they do not have any direct control over investments in generation, PUCs would most likely evaluate the utilities' energy procurement strategies, rather than judging the compliance costs themselves. However, if a state's compliance plan includes utility investment of ratepayer funds in measures such as demand-side energy efficiency or renewable energy, PUCs will have the authority to review this investment.

[9] Fifteen states have "restructured" their retail electricity markets: OR, TX, IL, MI, OH, PA, MD, DE, NJ, NY, CT, RI, MA, NH, and ME. Restructuring is the process of introducing increased amounts of competition into the electricity market.

Regional Entities

Multi-state coordination is common in electricity system planning, and numerous regional entities cooperate on different pieces of the puzzle. NERC oversees eight regional reliability councils, comprising utilities, power generators, power marketers, and end-use customers, which work to ensure adequate resources will be available to customers in their region. These councils cover between one and thirteen states and are charged with comparing future resource availability against future demand. The work of these councils is informed by a collection of planning areas, shown in Figure 2. These planning areas are generally overseen by electric utilities (investor-owned, municipal, cooperative, and federal power authorities), as well as Regional Transmission Organizations (RTOs).[10] The boundaries of NERC reliability regions do not match those of RTOs, although RTOs provide significant input to the NERC regional entities.

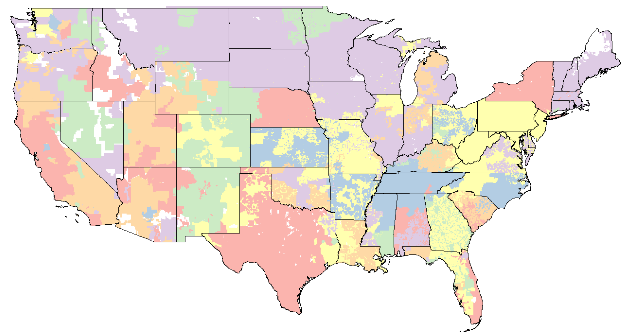

Figure 2: U.S. Planning Areas. (Source: Ventyx Velocity Suite)

In addition to the reliability councils, an array of other regional entities and coalitions often provide input into planning processes. For example, the Southeastern Electric Exchange, the Northwest Public Power Association, and the New England Power Generators Association all represent utilities and power generators. The New England Power Pool (NEPOOL) is a diverse association of market participants representing generators, transmission companies, suppliers, and end users of electricity. The New England Conference of Public Utilities Commissioners (NECPUC) and the Southeastern Association of Regulatory Utility Commissioners (SEARUC) are two regional associations of public utility commissioners. Each of these groups, and many others like them around the country, arranges member forums to facilitate the flow of information, considers and acts on pertinent policy and market proposals, and synthesizes comments when there is an opportunity to participate in stakeholder processes.

Given that Section 111(d) is likely to affect generators, planners, and market operators, and given the extensive interstate electricity trade that takes place, regional entities can be expected to be engaged before and after Section 111(d) standards and state compliance plans are finalized.

Before the standards are finalized, regional entities will likely begin to prepare by coordinating with one another. They can also be expected to participate in the public comment process during development of state compliance plans. Regional entities commonly provide feedback on rulemakings. As an example, the ISO/RTO Council, which is a collaboration of Independent System Operators (ISOs) and RTOs, has already submitted comments to EPA on Section 111(d).[11] Similarly, ISO New England, which is the New England-area RTO, and other regional coalitions were actively involved in developing the two model rules for the Regional Greenhouse Gas Initiative (RGGI). They helped RGGI market designers understand the impacts of proposed rules on electricity markets.

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[10] An RTO is an independent, standalone, non-profit organization set up by a consortium of transmission owners and grid operators to manage grid operations and electricity markets, and oversee system planning within a defined area. RTOs operate the grid on behalf of transmission owners, generators, and customers. Independent System Operators (ISOs) perform the same function as RTOs, with the slight difference that they are formed at the direction of FERC.

[11] ISO/RTO Council, EPA CO2 Rule–ISO/RTO Council Reliability Safety Valve and Regional Compliance Measurement and Proposals, January 28, 2014, http://www.isorto.org/Documents/Report/20140128_IRCProposal-ReliabilitySafetyValve-RegionalComplianceMeasurement_EPA-C02Rule.pdf.

Once the standards have been finalized, regional entities will need to incorporate revised assumptions into their planning models and participate in negotiations to establish any appropriate multi-state collaborations. For example, the Southwest Power Pool (SPP), which serves as a regional reliability council in the southwest, incorporates assumptions about emission allowance costs when it performs cost-benefit analyses of potential market design changes.[12] WECC, the Western Region Reliability Council, has conducted analyses to determine how California's AB32 greenhouse gas regulations should shape transmission planning in the West.[13]

RTO and non-RTO Regions – Planning

Electricity system planning and coordination takes place in both RTO and non-RTO regions, although the mechanisms for planning and coordination differ. RTOs plan and coordinate transmission for nearly two-thirds of all U.S. electricity systems. Participation by transmission system owners in an RTO is voluntary, but subject to PUC approval. As shown in Figure 3, the U.S. has seven RTOs/ISOs, including the PJM Interconnection, the Midcontinent Independent System Operator (MISO), ISO-New England, the California ISO (CAISO), the New York ISO (NYISO), the Southwest Power Pool (SPP), and the Electric Reliability Council of Texas (ERCOT).

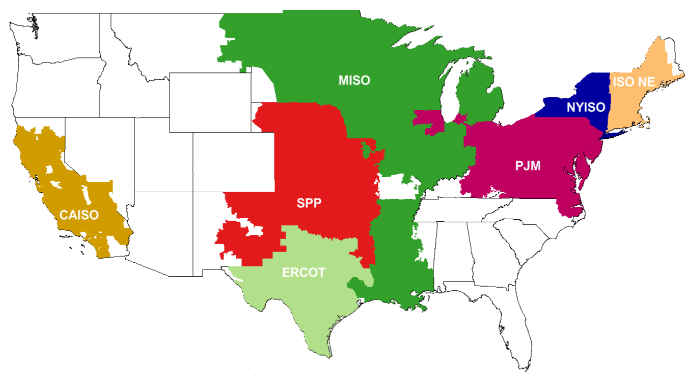

Figure 3: U.S. RTOs (Source: Ventyx Velocity Suite)

The largest non-RTO region in the U.S. is in the West, where public and investor-owned utilities (IOUs), system operators, independent power producers (IPPs), state agencies, cities and towns, trade associations, and various stakeholders participate in the Western Electricity Coordinating Council (WECC). WECC is one of the eight regional reliability councils designated by NERC to oversee system planning. Within WECC, utilities have formed several regional initiatives, including ColumbiaGrid, Northern Tier Transmission Group, and WestConnect. These entities are not formally RTOs, but perform many of the same long-term planning functions.

Another large non-RTO region is the Southeast, where the SERC Reliability Corporation (SERC) is responsible for overseeing regional reliability and leading coordination among parts or all of sixteen states.

Electricity system planning and coordination differ between regions that are within an RTO and those that are not. In general, in non-RTO regions, the level of market regulation tends to be higher, and PUCs exert greater influence in planning through administrative control over market pricing, investment, and market rules. In RTO regions, PUCs exert less influence over planning, and pricing and investment are the outcome of market rules and incentives, which RTOs manage on behalf of a large number of regional market participants.[14]

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[12] *See, e.g.*, Ventyx, Southwest Power Pool Cost Benefit Study for Future Market Design (April 7, 2009). http://www.spp.org/publications/cost_benefit_study_for_future_market_design.pdf

[13] *See, e.g.*, WECC, Draft Scoping Document, California AB32 Sensitivity Case for 2011 TEPPC Study Program (April 2012), http://www.wecc.biz/Lists/Calendar/Attachments/4502/TEPPCMWG_2022AB32_DRAFTScopingDoc.pdf.

[14] There are exceptions to this rule; utilities may be subject to grandfathered agreements, legislated provisions, or other special cases.

4. Scheduling, System Control, and Dispatch

Real-time operations of the electric grid are handled by grid operators. In RTO regions, this function is performed by RTOs. In non-RTO regions, grid operations and electricity dispatch are managed by electric utilities, which oversee "control areas" or "balancing authorities" for a defined region. In some places, federal power agencies serve this role. While decision rules and approaches vary around the country, in general, grid operators develop projections of electricity demand one or more days ahead of time and "schedule" generators by providing notice that they will be needed at a given time on a given day. In real-time, grid operators call, or "dispatch," the necessary units and instruct them to provide power.

The choice of which generators to dispatch is usually based on the marginal operating costs of each unit. In competitive markets, marginal operating costs are reflected in bids provided by generators, indicating the price at which they are offering to provide electricity and the amount of electricity they could provide at that price. Elsewhere, the grid operator has a list of available generators, their capacities, and their marginal operating costs. (Bids are generally based on these same factors.) In both cases, marginal operating costs include fuel costs, the variable costs of operations, and certain environmental costs, such as the cost of emission allowances.[15] The lowest-cost generators are called first, followed by the more expensive ones, until the cumulative capacity matches the total capacity demand.[16] This approach is known as "least-cost" or "economic" dispatch.

While most dispatch decisions reflect the least-cost principle, system operators may in certain circumstances take other factors into account in dispatch decisions, and choose to dispatch units "out of merit." For example, if demand is especially high in a given region, a system operator could choose to dispatch a generating unit due to its proximity to the demand, to overcome transmission congestion. The system operator could also choose to dispatch a unit to help ensure system reliability. In addition, dispatch may not include all of the lowest-cost units in a given market if generators choose not to offer their capacity to the market due to operating limitations.

Marginal Costs of Environmental Compliance

In the context of Section 111(d), one potential approach to reducing carbon pollution in the electricity sector is to reshuffle the dispatch order to account for greenhouse gas emissions. There are numerous ways to achieve this, such as (1) for the system operator to add an emissions fee to each generator's costs, (2) for each generator to be required to hold emissions allowances, the cost of which would be reflected in the marginal costs, (3) for units to be subjected to utilization limits, or (4) for fuels to be given dispatch preference based on carbon emissions. All of these approaches, and others, could theoretically be integrated into current approaches to dispatch. Already, generators include the cost of sulfur dioxide (SO_2) and nitrogen oxide (NO_x) allowances when they submit marginal cost bids to the system operator. In states that participate in RGGI, many generators include RGGI allowance costs in their bids to the ISO-NE and PJM market operators.

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15 The extent to which marginal costs include environmental costs is highly dependent on policy. Some environmental costs have been internalized into the operating costs, while others are not, and are instead borne by society.

16 A single market "clearing price" based on the highest marginal operating cost of units that will be dispatched will be paid to generators who participate in the market at a specified time. Therefore, generators with operating costs lower than the clearing price will earn profits from selling electricity. The profit is equal to the difference between the clearing price and their operating costs.

As part of a compliance plan, some emissions reductions may be attained through investments in the plant. As an example, a generator may invest in on-site efficiency measures. The capital investment in efficiency is not reflected in a generator's variable operating costs, but would be factored into the fixed costs that the generator must cover, either by seeking regulatory approval for cost recovery, or by earning profits on its sales of electricity and other services to the grid. (If the generator incurs costs to *run* the new equipment, those costs would be included in the marginal operating costs.) In regions where regulated plants and merchant plants compete against each other in the electricity market, regulated plants will benefit from greater certainty around their ability to recoup the efficiency investment.

Given the interstate nature of dispatch within the electricity system, dispatch will be affected by differences between states' Section 111(d) compliance plans that value carbon reductions differently in different states. For example, similar power plants competing in the same market or power pool could face very different compliance costs, which would change their competitiveness relative to each other.

Public Power Utilities

About 15 percent of the U.S. is served by community-owned utilities, notably municipal utilities and rural electric cooperatives ("munis and coops"). These utilities are owned by and accountable to customers, and in the case of munis, are administered by local municipal governments. They are generally not regulated by state utility commissions. Some of these entities own their own power generation, while others do not. The same principles of scheduling and dispatch apply to the power sold by munis and coops as those described above. In most cases, these entities purchase their power from suppliers who participate in an RTO market or are dispatched by a control area operator. The electricity sold by a muni or a coop to a customer may reflect economic dispatch, or it may reflect power purchase agreements between the muni/coop and a generator.

Public power utilities that own generation will be sensitive to compliance costs of their own fleet. Those that purchase power from the grid will be interested in understanding how the wholesale market price of electricity may be affected by state plans to reduce carbon emissions, and how their existing power purchase agreements are recognized under the relevant state's compliance plans.

Table 1: Anticipated Priorities of Regulators and other Market Entities.

	Likelihood that these entities…							
...will evaluate how 111(d) could affect…	FERC	NERC	PUC	RTO	IOU	Muni/Coop	IPP	Stakeholders
… retail power prices.			Definite		Definite	Definite		Definite
… resource adequacy.	Definite	Definite	Definite	Definite	Definite	Definite	Possible	Possible
… system reliability.	Definite	Definite	Definite	Definite	Possible	Possible	Possible	Definite
… transmission needs.	Definite	Possible	Possible	Possible	Possible	Possible	Possible	
… generator dispatch.			Possible	Definite	Possible	Possible	Possible	Possible
… wholesale electricity markets.	Definite		Possible	Definite	Possible	Possible	Possible	
… retail utility operations.			Definite		Definite	Definite		Definite

5. Conclusion

Maintaining a reliable electricity system requires the participation and input of many diverse entities with a mix of local, state, regional, and national authorities. The overlap between them speaks to the need for effective cooperation throughout the development of state plans under Section 111(d). Because a substantial share of U.S. electricity consumption crosses state lines, states will want to consider how best to drive efficient outcomes across multi-state markets. Many of the regulatory and market processes that could underpin a sound approach to carbon pollution reduction policies can already be found in practice.

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