STATEMENT OF THE ELECTRIC POWER SUPPLY ASSOCIATION

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Federal Energy Regulatory Commission
Reliability Technical Conference
[Docket No. AD15-7-000]

June 4, 2015

Thank you for inviting the Electric Power Supply Association ("EPSA") to participate in this year's Reliability Technical Conference on the Emerging Issues panel. This annual conference is always a welcome opportunity for all of us – regulators, NERC, market participants, and the public – to step back from the details of day-to-day dockets to look at the bigger picture as it relates to the enduring reliability of the nation's power grid and the systems and networks that support it. That has never been more important than today given all the changes and resulting challenges facing the power sector.

EPSA is the national trade association for leading competitive wholesale power suppliers. EPSA members in the aggregate represent over 200,000 megawatts of power supply essential to resource adequacy. EPSA members individually and collectively have a fuel diverse fleet: over half of member assets are natural gas-fired, including dual-fuel units; one-fifth is nuclear power; over one-sixth is coal; and the balance is renewable (wind, solar, geothermal and hydro). EPSA members are the largest or among the largest operators of each fuel type in the country. The broader competitive power sector accounts for over 40 percent of U.S. installed generating capacity, which approaches all or nearly all of the power supply on a regional and subregional basis. As large national market participants, EPSA members typically operate in multiple NERC Regions, often 4 or more. The bulk of EPSA member assets (over 95 percent) are in the organized markets, which continue to grow in large part thanks to the Commission's efforts to enhance competitive wholesale markets.

The charge to this panel began with the declaration that "[s]ignificant changes to our Nation's fuel sources and power supply portfolio could result" (emphasis added) from a series of factors including plentiful and affordable domestic natural gas, renewables policies and environmental regulations. We all know from headlines and statistics issued on a nearly daily basis that this is beyond something that "could" happen; rather, it is happening at an accelerating pace all around us. To the listed factors, one has to add technological developments that are altering the relative economics not only among conventional fuels, but between conventional fuels and new alternatives including distributed resources, energy storage, and other measures that empower and expand consumer choice.

EPSA has always stressed that at its core, from both resource adequacy and operational perspectives, reliability hinges on affordable and environmentally responsible supply. This supply requires generation from base load, mid-merit and peaking units deploying a range of fuels and technologies. Given that there is a need for all types of units, the preferred policy approach is to reinforce and refine market-based policies that are to the maximum extent possible fuel neutral: define attributes and let all appropriate sources that can provide those attributes compete in the wholesale markets. That is easier said than done given numerous recent and ongoing policy debates – from Congress to FERC to state legislatures and state regulatory commissions – as to how to strike the right balance between policy mandates and markets.

From EPSA's perspective, well-designed and properly regulated competitive wholesale markets remain the best model to manage these challenges and risks because they are more flexible, adaptable and place more risks on investors as opposed to consumers. Markets depend on ample opportunities – not guarantees, but opportunities – for suppliers to recover costs and earn a fair risk-adjusted return of and on investment from market-derived revenues.

Thus, reliability from a supply perspective in the competitive wholesale markets now serving over two-thirds of the country relies on an often changing mix of sufficient resources to meet or exceed reserve margins. These supply resources are a function of ongoing investment decisions being made by a multitude of market participants, including developers, owners and operators of power plants, as well as their lenders and investors. These market participants need to make efficient resource decisions as to existing plants and potential new facilities based on accurate price signals and associated revenues. In the organized markets, price signals and revenues are tightly bounded by FERC-approved market designs and tariff rules along with RTO/ISO grid operator actions. <u>As a result, the single most important emerging issue from EPSA's point of view for the Commission to address is energy price formation. The Commission and its staff have accomplished a great deal on energy price formation over the past two years in terms of technical analysis; now is the time for the Commission to take concrete public steps leading to specific RTO improvements.</u>

Competitive suppliers look at revenue from three primary sources when making investment decisions – energy, capacity and ancillary services markets. While the Commission has for years spent a great deal of time on the important issues around capacity markets and ancillary services, far less time has been spent on the largest revenue source, the energy markets. The three technical conferences held in the latter third of 2014, the staff papers which preceded them, and the public comments taken in response to detailed questions earlier this year together form an extensive and compelling record that modifications to energy price formation in the organized markets are required.[1] As outlined in the attachment, these reforms should focus on improved energy market pricing that includes the costs of actions taken in the name of reliability in the Locational Marginal Prices and less so through out-of-market uplift payments that are opaque and cannot be hedged; greater transparency around operator actions and their consequences so that causes of uplift can be identified and market solutions developed; lifting or changes to outdated energy offer caps; sub-hourly pricing to better reflect actual market conditions which among other things will better compensate increased need for ramping as intermittent resources increase; and intra-day offer flexibility.[2]

EPSA cannot overstate the importance of public Commission follow up in the next several months given that an array of investment decisions as to whether to retire, repower, or replace large amounts of existing megawatts in major markets, and

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[1] *Price Formation in Energy and Ancillary Services Markets Operated by [RTOs] and [ISOs]*, Docket No. AD14-14-000, Comments of the Electric Power Supply Association (filed March 6, 2015), http://elibrary.ferc.gov/idmws/common/opennat.asp?fileID=13795045.

[2] *See attached* EPSA Energy Price Formation Priority Principles, May 2015.

decisions as to new units, will continue to be made – decisions that, among other key factors, turn on the expectations of market participants about whether the identified imperfections in energy market formation will be addressed so that expectations about future energy prices and revenues better reflect actual system operating needs and conditions. Simply stated, inaccurate price signals run a substantial risk of insufficient and inefficient investments in power supply. It is clear from the record developed to date that waiting for individual RTOs to act on their own timelines will be too little, too late. RTOs react to the priorities as set by the Commission. Thus, Commission leadership is the key if energy price formation is to be improved in sufficient time to avoid the adverse consequences of investment decisions as to existing and new plants based on muted price signals for the primary revenue stream on which such investment decisions must be made.

EPSA is not alone in stressing the importance of energy price formation. In our latest letter to the Commission, EPSA was pleased to be part of an unprecedented coalition that includes the Edison Electric Institute, the Nuclear Energy Institute, the Natural Gas Supply Association and America's Natural Gas Alliance.[3] At the core of the reform principles shared with FERC in that letter and the recommendations that flow from those principles is the fuel-neutral foundation consistent with competitive wholesale markets – a rising tide lifts all boats – to the benefit of suppliers and consumers. The much less desirable outcome – which is what will likely happen in the absence of Commission and RTO action in the coming few months – is a further

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[3] *Price Formation in Energy and Ancillary Services Markets Operated by [RTOs] and [ISOs]*, Docket No. AD14-14-000, Letter on Joint Price Formation Principles from EPSA, EEI, NEI, NGSA and ANGA, (submitted March 9, 2015), http://elibrary.ferc.gov/idmws/common/opennat.asp?fileID=13797119.

balkanization by fuel type and plant location with more and more requests for out-of-market support mechanisms, thus eroding rather than reinforcing the competitive wholesale markets that the Commission has spent decades developing.

To the specific questions the panel is asked to address, energy price formation goes beyond the scope of long-term, seasonal and operational planning studies. While there is a role for such studies in identifying issues and considering alternatives, as noted above, only the Commission and the RTOs can make the market design, tariff, and operational improvements required for more accurate price formation so that efficient investment decisions are made to support reliable fuel sources and power supplies, thereby addressing reserve margin concerns and resource adequacy generally.

NERC's Essential Reliability Services Task Force, of which EPSA and EPSA members are active participants, has made progress in educating policymakers and to a lesser extent the broader public about the critical importance of voltage support, ramping capability and frequency support that were once taken for granted as a byproduct or co-benefit of the "rotating mass machines" that made up the power fleet in the past but no longer do so exclusively today (and will less so in the future). Not every megawatt of supply or demand-side resources is created equal when it comes to providing these essential services.

However, consistent with what EPSA understands is NERC's overall hesitancy (and perhaps generally understandable reluctance to wade too far into policy), the engineers who dominate the task force's work, and do so generally for good reason, stop at the water's edge of the economics required to provide sufficient amounts of these essential reliability services in a competitive wholesale market. Changes in reliability standards – the usual domain of NERC's work – are not enough in the real world. Like the Commission's work on energy price formation and capacity markets, NERC's Essential Reliability Services Task Force has been years in the making. To be as candid and direct as possible given the high stakes involved, the markets need products and services with sufficient revenues to support the coming and inevitable changes to the system. The engineers need to talk to the economists – or the excellent work of the engineers needs to be complemented by rigorous economic analysis by others outside of NERC – to make sure essential reliability services are properly compensated and therefore available in the real world in a timely manner.

The Commission is to be commended for its multi-year work to address <u>coordination issues between the natural gas and electricity markets</u>. Much progress has been made to date and the potential for more is at hand. As the RTOs look to respond by July 23, 2015, to the Commission's Order No. 809 on adjustments to electric day operations in light of recently approved changes on the natural gas side, EPSA is urging the RTOs to look hard at more efficient RTO processing times in determining and publishing Day Ahead commitments so that market participants have as many opportunities as possible to procure natural gas supplies while those markets are the most liquid. In addition, another critical improvement would be for the Commission to direct PJM Interconnection to join the rest of the RTOs in providing greater intraday offer flexibility so that energy market bids reflect actual and accurate natural gas fuel costs. At present, unlike what EPSA would consider a "best practice" in other RTOs, PJM requires a single price for each hour of the 24-hour electric day and only a single limited opportunity to refresh that bid. Instead, market participants in PJM should have the flexibility as they do elsewhere to submit bids with prices that vary within a 24-hour period and a complementary ability to update those prices as market conditions change, particularly as to fuel input costs given what can be sudden and significant changes in natural gas supply and delivery costs.

Finally, with respect to the Clean Power Plan, EPSA spoke at the initial national technical conference on February 19, 2015, and EPSA member representatives spoke at one or more of the various regional conferences that followed. The Commission correctly stated throughout this process that it was focused on reliability, infrastructure and markets. The Commission's recent letter to EPA focused on reliability mechanisms. EPSA stressed on February 19 that FERC is uniquely qualified and indeed responsible for addressing aspects of the Clean Power Plan that might undermine the operation of competitive wholesale markets. At that time, EPSA's testimony focused on the importance of making sure the Clean Power Plan is developed and implemented consistent with the bid-based, security-constrained economic dispatch that is a bedrock of wholesale power market design. FERC's expertise and central role in assessing the impacts of EPA environmental regulations on the energy markets and reliability was subsequently confirmed by the U.S. Court of Appeals for the District of Columbia Circuit in *Delaware Department of Natural Resources and Environmental Control v. Environmental Protection Agency*, Nos. 13-1093, *et al.*, 2015 WL 194736 (D.C. Cir. May 1, 2015). In that case, a unanimous three-judge panel overturned an EPA rule exempting certain behind-the-meter generators used in demand response programs from hazardous air pollution requirements. In doing so, the court noted the adverse effects of such an exemption on power markets and reliability, and stressed FERC's expertise in this area, encouraging EPA to work with FERC on remand.

EPSA has just released a new report prepared by The Analysis Group entitled "Carbon Control and Competitive Wholesale Electricity Markets: Compliance Paths for Efficient Market Outcomes"[4] that goes into more detail on how aspects of the Clean Power Plan could interfere with or undermine competitive market outcomes. This largely stems from the proposed state-by-state emissions rate-based approach in the Clean Power Plan that could produce market-distorting results given widely varying numerical targets among states within the same RTO. Thus, the same or similarly situated power plants competing in the same regional power market will receive potentially widely varying revenue streams merely as a function of what state they are located in, even though power flows do not follow state boundaries.

Similarly, the scope of the Clean Power Plan covers "existing" power plants while "new" power plants (defined as those with a commercial operation date after January 1, 2014) are not automatically covered within the Clean Power Plan's emission rate targets to which existing plants must comply from the start. Thus, under the real world scenarios outlined in the Analysis Group report, "new" power plants operating outside of the Clean Power Plan under the separately proposed New Source Performance Standards would be artificially advantaged to the detriment of accurate price signals for all existing power plants, including "existing" natural gas-fired power plants. The report

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4 *See report attached*, "Carbon Control and Competitive Wholesale Electricity Markets: Compliance Paths for Efficient Market Outcomes," prepared as an independent report by Susan F. Tierney and Paul J. Hibbard of the Analysis Group and funded by Electric Power Supply Association, May 2015, also available at www.epsa.org.

outlines options for states to implement the Clean Power Plan more consistently within regional markets, and for EPA, with FERC's help, to encourage states to place "new" power plants within the Clean Power Plan's structure as rapidly as possible. It took Congress years to address the distortions of vintage pricing of "old" and "new" natural gas under price controls enacted in 1978; FERC should work with EPA to avoid repeating that costly mistake again.

As always, EPSA greatly appreciates the Commission's indispensable leadership on wholesale market issues. Wholesale competitive markets have been decades in the making and continue to evolve while providing a range of benefits to consumers, the environment and the economy. All electricity business models and associated regulatory paradigms – whether cost-of-service vertically-integrated utility regulation or market-based competitive market design, tariffs and operator practices – must rapidly improve to keep pace with the changes occurring due to technological, economic and policy developments. Many often say – and correctly so – that reliability is job one and EPSA agrees. To keep pace and manage reliability challenges successfully, quickly following through on energy market price formation reforms, improved compensation for essential reliability services, further natural gas/electric coordination improvements, and addressing the potential wholesale power market impacts of the Clean Power Plan are the emergent and emerging issues on which Commission leadership is essential at this time.

ATTACHMENTS TO
STATEMENT OF THE
ELECTRIC POWER SUPPLY ASSOCIATION

Federal Energy Regulatory Commission
Reliability Technical Conference
[Docket No. AD15-7-000]
June 4, 2015

Energy Price Formation Priority Principles

Electric Power Supply Association
May 2015

Co-optimizing energy and reserves Day Ahead: To better align commitment with dispatch, products purchased and sold in the Day-Ahead and Real-Time Energy and Operating Reserve Markets should be cleared together in simultaneous co-optimized solutions in order to ensure that there is enough energy online and available for system demands. "Simultaneous co-optimization" means that all four products – Day Ahead energy and reserves and Real Time energy and reserves -- are considered at the same time, in the same Economic Dispatch formulation. The result is that each resource is economically indifferent as to which product or combination of products it clears.

This process should incorporate reliability commitments into the Day Ahead market clearing and price-setting algorithms. This allows energy prices to reflect the actual marginal costs incurred by the marginal generator and minimizes uplift (done in NYISO for a decade).

Additionally, the process should: (1) incorporate the costs of block loaded peakers, including start-up and no-load costs, in to the Day Ahead price; (2) include in the pricing algorithm any conservative operations that occur after the Day Ahead reliability process so that they are included in the Real Time price; and (3) utilize an Operating Reserve Demand Curve Day Ahead for procurement and payment of reserves through the Day Ahead market scheduling and pricing (it is critical that the reserve pricing be included in the Day Ahead clearing process).

Transparency: The guiding principle is that there should be sufficient information available to allow a market participant to replicate the decisions and actions of the operator close to real time (shortly after the trading day). This level of transparency (number of units, hourly MW, duration of uneconomic dispatch) ensures that operator actions and decisions are better understood and, therefore, market rules and practices can be changed to ensure all such actions and decisions can be priced in to the LMP.

More broadly, RTOs should submit to FERC monthly standardized reports summarizing uplift which includes information on the type of out-of-market dispatch, the reason for dispatch, the date of dispatch, the reliability zone (for instance, Locational Deliverability Area in PJM), and the magnitude of out-of-market dispatches. Once the driving forces of repeated and avoidable uplift are exposed, possible supply, transmission or other solutions can be identified and evaluated and changes to protocols, procedures, operator discretion and market design can be proposed and evaluated. Such improvements could occur RTO by RTO, or inform a FERC-initiated Section 206 proceeding which identifies the major sources of uplift and proposes a plan to fix recurring causes.

Information that should be made more transparent includes:

1. *Models or Algorithms*: Analysis tools that create the foundation of discretionary operator actions should be transparent to market participants. The nature of the inputs and outputs of those models should be shared with and understood by market participants. Similarly, the boundaries of operator discretion and levels of management review required for extra-ordinary operator action should be clear in the tariff.

2. *Operator Manual Adjustments*: Any non-market adjustments to model inputs or model results should be publicly disclosed (examples include load bias adjustments, conservative dispatch adjustments based on changes to generation outage expectations, intertie biases, RUC bias due to changes in variable resource forecast).

3. *Uneconomic Unit Commitments*: including long-start units committed before DA market, RUC committed after DA but before RT. Data required: number of units, hourly MW, duration of uneconomic dispatch

To be illustrative, NYISO utilizes a best practice as follows: All operator initiated out of market actions are listed in the daily operational announcements as the actions are taken, reporting the specific unit and time of the out of market action. In cases of out of market commitments, the unit is listed, as well as the hours and level the unit will be committed out of market. The NYISO also lists summary information on the amount of out of merit commitments for the market in the monthly operations reports that are provided to the NYISO Committees. In most cases the report identifies the specific unit that was committed out of merit and the amount of hours for the month that the unit was out of merit. When this occurs outside New York City and Long Island, the NYISO report also identifies the total local reliability cost by unit.

Sub-hourly Settlement: The principle is that settlement should match pricing, both optimally in 5-minute increments. Compensating resources at this more granular price will help improve market signals for resource performance by better aligning prices and payments. This change helps improve price formation by ensuring that the price suppliers are paid for real-time performance is a more accurate market signal of the power system's current operating conditions.

When payments are averaged as an hourly price at the resource's location, certain resources tend to be undercompensated, particularly more flexible generation assets that respond quickly when system events result in tight operating conditions and there are significant mid-hour price changes.

Offer Caps: This over-mitigation issue, based on an existing and extensive record and precedential waiver approvals from the Commission, should be addressed on its own separate procedural track. Removing or modifying the energy market offer cap is critical for allowing resources to recover costs incurred to run, particularly during times of system stress. It is important that any revised cap is sufficiently standard across regional markets so that interchange issues are not impacted by the imposition of differing offer cap limits or structures. This is a clear structural issue which needs attention before the upcoming winter.

Intraday Offer Flexibility: At this time only lacking in PJM, the ability to refresh energy offers on an intraday basis, optimally hourly, is critical so that sellers can adjust real-time offers to account for fuel price volatility between the Day Ahead and Real Time markets. This ensures that generators are able to reflect actual fuel prices in their offers, which is of particular importance when natural gas prices are volatile. There is a connection between this issue and energy offer caps as both relate to the ability of generators to reflect more accurate reasonable and supportable costs in energy market offers. This ability is central to adequate price formation and therefore is a market mechanism that should be implemented in every market. FERC should direct PJM to adopt this best practice as other RTOs have already done.

ANALYSIS GROUP
ECONOMIC, FINANCIAL and STRATEGY CONSULTANTS

Carbon Control and Competitive Wholesale Electricity Markets:
Compliance Paths for Efficient Market Outcomes

Analysis Group
Susan F. Tierney
Paul J. Hibbard

May 2015

Acknowledgments

This report presents a review of the potential impact of various intra- and inter-state Clean Power Plan compliance options on the efficiency of and pricing in wholesale electricity markets. It also presents implications of the interaction between compliance strategies and competitive markets for the cost of carbon control across the states. This is an independent report by Analysis Group, supported by funding from the Electric Power Supply Association (EPSA). The authors wish to thank EPSA for its support of the analysis presented in this report. The views and opinions expressed in this study, however, are solely those of the authors and do not necessarily reflect the views and opinions of Analysis Group, employees and other affiliates of Analysis Group, EPSA as an organization, or any particular EPSA member with respect to any issue.

About Analysis Group

Analysis Group provides economic, financial, and business strategy consulting to leading law firms, corporations, and government agencies. The firm has more than 600 professionals, with offices in Boston, Chicago, Dallas, Denver, Los Angeles, Menlo Park, New York, San Francisco, Washington, D.C., Montreal, and Beijing.

Analysis Group's energy and environment practice is distinguished by expertise in economics, finance, market analysis, regulatory issues, and public policy, as well as significant experience in environmental economics and energy infrastructure development. The practice has worked for a wide variety of clients including energy producers, suppliers and consumers; utilities; regulatory commissions and other public agencies; tribal governments; power system operators; foundations; financial institutions; and start-up companies, among others.

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EXECUTIVE SUMMARY

Acting under its existing authorities under the Clean Air Act (CAA), the U.S. Environmental Protection Agency (EPA) has been developing proposals designed to reduce carbon dioxide (CO_2) emissions from new and existing fossil-fuel power plants in the United States.

> Power production is the nation's largest source of carbon emissions, contributing 37 percent of all CO_2 emissions in the U.S. This will be the first time that federal policy will broadly address CO_2 emissions from the power sector, and EPA's new policies will affect over half of the nation's existing generating capacity.

EPA and the electric sector have a long track record of successful market-based, regional emission-allowance-trading programs, which can serve as a template for the regulation of CO_2 emissions.

> Such programs – for example, the Acid Rain sulfur dioxide (SO_2) trading Program, the "NO_x SIP Call," and the Regional Greenhouse Gas Initiative (RGGI) – provide price signals to power plant owners so that they can make their own choices about their lowest-cost path to compliance. These programs have proven to allow for environmental improvements at much lower cost to both power plant owners and electricity consumers.

There is a natural fit between market-based emission-control programs and competitive wholesale power markets.

> Most of the power plants covered by EPA's Clean Power Plan operate in competitive wholesale electric markets administered by an Independent System Operator (ISO) or Regional Transmission Organization (RTO) (collectively "RTO"). These regions span more than two-thirds of the states, encompass 70 percent of the nation's generating capacity, and serve the electricity needs of two-thirds of the American people.

The CAA allows EPA and the states to establish an emission-allowance trading system for the control of CO_2 from existing and new power plants.

> States will ultimately decide how to design their implementation plans considering state-specific industry structures, circumstances, and policy objectives. How states choose to implement the rules for existing and new power plants will affect the competitive conditions as well as overall compliance costs – positively or negatively – in wholesale power markets around the U.S.

States should take into consideration the potential ramifications of their State Plan designs on competitive power markets so as to avoid unintended and costly market distortions.

Although the 111(d) rule is focused on existing power plants, the regulation will alter the competitive landscape for both new and existing power plants. Taking into consideration both of the upcoming EPA rules under 111(b) and 111(d) of the CAA, regulating new and existing plants, respectively, the proposed rule allows states to choose whether to include the new power plants in the program affecting existing electric generating units (EGUs). We encourage them to do so, to avoid market distortions. All existing trading programs, including the Acid Rain trading program and RGGI, include both new and existing sources.

A competitively neutral design of an emission-trading program would be one where the states in an RTO voluntarily elect to prepare and implement a multi-state, mass-based plan covering all of the existing generators and new units within the footprint of the RTO. The overall cap on emissions would be set at the sum of all of the participating states' mass-based emissions goals for those EGUs. With all EGUs in the market facing the same carbon price, system operators would be able to optimize the dispatch of the generating fleet to minimize both energy production costs and costs to reduce CO_2 emissions.

By contrast, an economically *inefficient* approach would be one in which at least some states exclude new generating units from the program. This would lead to competitive distortions without necessarily producing CO_2-emission reductions or cost savings to consumers. With some states excluding new gas plants from the program, states would create economic incentives for developers to build new gas-fired generating units in states where such plants would be excluded from the mass-based program. The output from these plants would likely to shift from existing gas-fired units without a net reduction in emissions or costs to consumers.

There are other, equally bad inefficiencies that could arise with some program designs, including situations where different states in an RTO adopt mass-based approaches and others adopt rate-based designs. This would create distortions in the competitive wholesale market and in the cost per ton of CO_2 emissions reduced.

In short, the design and administration of a new environmental regulation can create competitive advantages and disadvantages for different power plants and varying financial impacts for different power plant owners – with cost impacts for consumers.

To design a State Plan that is compatible with the functioning of competitive power markets (i.e., enabling them to produce and deliver power efficiently and reliably) and to produce cost-effective CO_2-emission reductions, the states in a common RTO market should support an approach that treats similarly situated competitors in similar ways, with all of them facing an incentive to control carbon emissions as economically as possible.

EPA's Clean Power Plan proposal has given the states broad discretion about how to design their compliance plans.

Ideally, states will elect to adopt plans that align with the character of the electric industry structure affecting power plants in different parts of their states. States should adopt State Plan elements that encourage power plant owners to make economically-rational decisions. In regions with organized multi-state wholesale power markets, this would mean that states would proactively work with their counterparts in the region to develop a common multi-state approach with similar core elements. Even if they don't file a single joint multi-state plan, the states in an RTO should design their plans to be compatible with one another.

There are benefits of a multi-state, mass-based emission-trading program that provides for emissions-averaging across the footprint of the system as a whole, and folds new units into the system at the time of their entering commercial operation (or shortly thereafter).

These benefits include: economically efficient power supply; lower-cost CO_2 compliance; lower overall costs to electricity consumers; reliability assurance; administrative simplicity; equity among power suppliers; and environmental integrity.

We strongly encourage states with electric generating units in RTO power markets to coordinate the development of their state plans and elect to participate in a common, mass-based multi-state emission-trading program that covers both existing electric generating units and new fossil generating facilities.

We hope that states will decide for themselves that this is the core element of a pathway toward least-cost CO_2 compliance and an efficient, reliable power system for the benefit of their consumers.

We think that a well-designed multi-state mass-based system dovetails with other state policies and note in particular the findings of so many analyses that indicate that the overall cost of compliance will be lower with energy efficiency as a complementary strategy.

We also encourage EPA to provide incentives for states to adopt mass-based approaches that include both new and existing fossil generating units.

1. EPA RULES FOR CARBON EMISSIONS FROM POWER PLANTS

Introduction: EPA's Proposals for New and Existing Electric Generating Units

Over the past several years and acting under its existing authorities under Sections 111(b) and 111(d) of the Clean Air Act (CAA), the U.S. Environmental Protection Agency (EPA) has been developing proposals designed to reduce carbon dioxide (CO_2) emissions from new and existing fossil-fuel power plants in the United States. EPA is targeting the power sector in part because power production is the nation's largest source of carbon emissions, contributing roughly one third of all greenhouse gas (GHG) emissions in the U.S.[1]

The current Clean Power Plan proposal was developed under Section 111(d) of the CAA. Under this section of the CAA, EPA sets emission standards for each state and provides guidance for state implementation but leaves much of the design and administration of emission controls to the states. In June 2014, EPA proposed the Clean Power Plan with state-specific emissions standards for existing fossil-fueled power plants. The final rule, anticipated in mid-summer 2015, will require each of the 49 states with affected power plants to prepare and submit a plan for how it proposes to reduce emissions from the affected generating units in its state.

Although the features of the final regulations will undoubtedly change in light of the many comments filed, EPA's current proposal requires states and affected electric generating units (EGUs) to demonstrate progress toward emission reductions starting in 2020 and with a subsequent reduction after 2030. This new policy will eventually affect over half of the nation's existing generating capacity and all but the smallest fossil-fuel generating units.

The proposed Clean Power Plan came months after EPA published its proposed uniform national standards under the CAA's Section 111(b) to limit the amount of CO_2 emissions from certain new generating units that use natural gas or coal to produce electricity.[2] To obtain a New Source Performance Standard (NSPS) permit addressing air emissions in the future, developers of new natural gas-fired combined-cycle units (NGCCs) and new

[1] Power generation contributed 37 percent of total CO_2 emissions and 31 percent of all GHG emissions in the U.S. in 2013. See Table ES-1 in EPA, "Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2013," April 15, 2015. The next largest sources of CO_2 emissions are: transportation (31 percent), industrial (15 percent), residential (6 percent), and commercial (4 percent).

[2] With certain exceptions, the proposed 111(b) rule would apply to EGUs commencing construction after the publication of the proposed regulation in 2014.

coal-fired power plants would need to show that their projects satisfy the new standards. EPA also expects to finalize these rules during mid-summer 2015.

The Context for Regulating Emissions from Power Plants

Controlling environmental impacts from power plants is nothing new. For many decades, the developers and operators of power plants have been responsible for managing the impact of changing – and often complicated – local, state, and federal environmental regulatory obligations. Since the CAA was initially enacted in the early 1960s, for example, it has been amended four times.[3] Each statutory iteration has altered the mix of control requirements on criteria pollutants (such as sulfur dioxide (SO_2), nitrogen oxides (NO_x), particulate matter) for certain affected electric generating units, sometimes in major ways. EPA's and the states' administration of CAA requirements has also continuously evolved over time, leading to a wide variety of air emission-control requirements on affected units.

Controlling environmental impacts from power plants is nothing new.

The CAA is only one example in a long list of different federal, state and local laws and regulations addressing the public health, safety and environmental impacts of electricity generators.[4] EPA's proposed structure for controlling emissions of CO_2 is but the latest iteration of environmental law and policy that began in earnest several decades ago.

Owners of affected power plants have thus often faced new incremental capital investments and increased operating costs to comply with evolving health, safety, and environmental regulations. Power plant owners (and regulators) in turn have needed to figure out how to recoup incremental investments and operating costs through prices or rates charged for electricity sales.

Power plant owners recover emission-control costs in very different ways, depending upon the structure of the electric industry in which they operate. Typically, vertically integrated investor-owned utilities (IOUs) face cost-of-service regulation with rates set by state public utility commissions (PUCs); municipal electric utilities, cooperatives, and

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[3] The CAA was first passed in 1963, with amendments in 1967, 1970, 1977, and 1990. Energy Information Administration (EIA), *Electricity Generation and Environmental Externalities: Case Studies*, September 1995, page 17.

[4] The list that includes, for example, the National Environmental Policy Act (NEPA), the Clean Water Act, the Endangered Species Act, the Resource Conservation and Recovery Act, and countless other standards and requirements with significant variation across states and source categories.

federal authorities have rates based on costs pursuant to the decisions of elected or appointed boards (and in some states, by PUCs).

Non-utility owners of merchant generating assets attempt to recover their costs in bilateral contracts with customers and utilities or in the wholesale markets administered by RTOs.[5] Such merchant plant owners, however, may or may not be able to do so, depending upon competitive market conditions.

Their ability to do so is greatly affected by the manner in which pollution-control programs are designed and administered. In the ideal (from an efficient and competitive wholesale-market point of view), pollution-control requirements could be administered in a way that achieves comparable cost metrics for similar assets (e.g., dollars per unit of pollution reduced or avoided), regardless of technology or fuel used to generate power.

Allowance trading programs have demonstrated the ability to overcome many of the complexities of emission control program design.

In practice, this goal is often frustrated by the fact that environmental laws are rarely if ever enacted with provisions aimed at maximizing both environmental and competitive-market outcomes. Also, these environmental laws are administered across states and regions with quite varied electric-industry and market structure, technological mix, and asset size and age.[6]

The successful track record of market-based, regional emission-allowance trading

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[5] See Section 2 for a discussion of RTO competitive wholesale markets, with a primer on market design and operations in the Appendix.

[6] Laws and regulations to control pollution, emissions or discharges often treat different classes of generating units differently in light of variations in their age, economics, location, readiness of commercially available control technologies, and so forth. For example, many pollution-control programs apply prospectively and sometimes grandfather existing EGUs while imposing control requirements on new units. As pollution-control technologies evolve over time, successive new power plants may face application of different "best available control" technologies.

Also, different parts of the CAA require that EPA use one type of pollution-control mechanism for one type of pollutant and another type for a different one. For example, such different approaches might involve unit-specific technology requirements or emission-rate limitations (e.g., for the Mercury and Air Toxics Standard (MATS)); consumption or flow limits (or performance standards) (e.g., for NSPS for criteria pollutants in new power plants); emission-rate averaging or "bubbling" (e.g., across units at a single station, or among plants owned by a single owner; e.g., for volatile organic compounds and other emissions in many states' current State Implementation Plans); state, regional, or national emission caps and allowance-trading programs (e.g., the national Title IV Acid Rain Program with its cap on SO_2 emissions and its emissions-trading program; the 9-state RGGI program); and pollutant taxes, fees, offsets, and power-plant operating limits and other restrictions in permits.

programs – beginning with the 1990 CAA Amendment's Title IV cap-and-trade program for SO_2 emissions from power plants – has fundamentally shifted the way that emission-control programs can be designed and administered. Such an approach aligns well with competitive power markets and overcomes many of the complexities associated with other emission-control program designs. Such a program design establishes one value on the margin for a ton of emissions and similarly affects all generating units covered by the program (regardless of age, type, location, etc.). In this way, emission-control requirements are set so as to price emissions on a fair and equal basis across resources that are competing head to head in energy markets. This creates conditions for cost-effective compliance without interfering with energy-market dynamics. This approach relies on market forces rather than administrative decisions to provide signals to generating-unit owners about their lowest-cost path to compliance and allows for an efficient overall cost of compliance.[7]

[7] For example, the Acid Rain Program "is largely considered a successful cap-and-trade system. By 2007, the program had achieved its 2010 reduction goal at an estimated cost that was considerably lower than that of *command-and-control* regulations, which mandate that each power plant adopt a specific technology to reduce SO2 emissions or a standard that requires each power plant to emit below a specific fraction of SO2 emissions per unit energy produced." Juha Siikamäki, Dallas Burtraw, Joseph Maher, and Clayton Munnings, "The U.S. Environmental Protection Agency's Acid Rain Program," November 2012. http://www.rff.org/RFF/Documents/RFF-Bck-AcidRainProgram.pdf. Also, a recent retrospective review of various studies of the effectiveness of the SO_2-emissions trading policy reviewed actual costs of the program relative to predicted costs prior to the program's implementation as well as "how the costs of achieving environmental objectives through cap and trade compare with those of a "counterfactual" (hypothetical alternative) command-and-control regulatory approach. "In addition to being less costly than traditional command-and-control policies would have been, the program's costs were significantly below estimates generated by government and industry analysts in the debate leading up to the passage of the CAAA. In 1990, the U.S. Environmental Protection Agency (EPA) estimated the cost of implementing the Acid Rain Program (with allowance trading) at $6.1 billion. In 1998, the Electric Power Research Institute (EPRI), an industry organization, and Resources for the Future (RFF), an independent think tank, estimated that total implementation costs would be $1.7 and $1.1 billion respectively (based in part on actual figures for the first few years of the program…). In sum, the SO_2 allowance-trading system's actual costs, even if they exceeded the cost-effective ideal for a cap-and-trade system, were much lower than would have been incurred with a comparable traditional regulatory approach, and were much lower than the trading system's predicted costs. There is broad agreement that the SO_2 allowance-trading system provided a compelling demonstration of the cost advantages of a market-based approach." Gabriel Chan, Robert Stavins, Robert Stowe, and Richard Sweeney, "The SO_2 Allowance Trading System and the Clean Air Act Amendments of 1990: Reflections on Twenty Years of Policy Innovation," Harvard Environmental Economics Program, January 2012. http://www.hks.harvard.edu/fs/rstavins/Monographs_&_Reports/SO2-Brief.pdf.

CO_2 Emission Control for New and Existing Power Plants: States' Compliance Choices Matter

The framework for control of CO_2 emissions from existing and new power plants, as dictated by the CAA and proposed by EPA, allows for but does not require an emission-allowance trading system. Instead, states will ultimately decide how to design their compliance plans considering state-specific industry structures, circumstances, and policy objectives.

How states choose to implement the rules for existing and new power plants is hugely important. It will affect the competitive landscape and conditions of wholesale power markets around the U.S., thus affecting power prices, and it will ultimately affect – positively or negatively depending on compliance paths chosen – overall CO_2 compliance costs. Under some compliance plan approaches, states in a common multi-state electric market could choose to design their compliance plans in ways that create distortions in those markets. Other approaches will avoid or minimize such outcomes, while simultaneously creating conditions for minimizing compliance costs. As we describe below, these effects are particularly relevant in the parts of the country where EGUs operate in centrally administered competitive wholesale power markets.

EPA's proposed Clean Power Plan creates opportunities for states to plan their compliance strategies to avoid introduction of competitive inequities and inefficiencies. Indeed, a state's plan can proactively incorporate design elements that allow for economically efficient outcomes in both power markets and carbon-control costs.

As states consider their compliance options with that goal in mind, it is important to take into consideration the implications of implementation choices for *both* existing and new power plants, together. By the time a State Plan is implemented, in combination with Section 111(b)/NSPS standards, it will affect how existing and new power plants compete (against each other) in electricity markets. In contrast, most discussions of the impacts of the EPA's regulations to this point have tended to focus primarily or exclusively on impacts on existing power-system elements only.

Potential compliance approaches will need to start with the fundamental structure of the requirements for new and existing sources, which differ as follows:

- *Existing Units under the Clean Power Plan, CAA Section 111(d)*: EPA's proposed Clean Power Plan establishes state-specific output-based emission-performance standards (in pounds of CO_2 per megawatt-hour (MWh)). Although the proposed standards are based on EPA's assessment of each state's ability to reduce carbon emissions through an analysis that combines four "building blocks,"[8] each state is free to select how it will comply, provided the state's Plan ensures that the EGUs in the state meet the standard. Specifically, EPA has not proposed that each affected EGU meet the standard; instead, EPA has proposed that each state determine how to meet the standard on average across all of the EGUs in the state, considering various power sector CO_2–reducing options (including, e.g., demand-side energy efficiency). Each state may select from a wide range of compliance approaches, may roll new units into the plan, and may design its approach on its own or in collaboration with other states.

- *New Units under CAA Section 111(b):*[9] To obtain an operating permit under the NSPS program, certain new fossil-fueled power plants[10] will have to meet performance standards for CO_2 emissions. As proposed, new stationary combustion turbines must be at or below the emissions rate of new NGCC units, at different size categories. This means that NGCC projects will be able to meet the standards without the need for add-on emission-control technologies.[11] The rule also includes slightly different limits for fossil fuel-fired utility boilers and integrated gasification combined cycle (IGCC) units.[12]

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[8] The four building blocks are: (1) improvements in generating-unit operating efficiency (e.g., heat-rate improvements); (2) reducing emissions from the most carbon-intensive EGUs through substitution of output at lower-emitting EGUs (e.g., operating gas-fired power plants at higher capacity factors); (3) reducing emissions from EGUs by substituting output at power plants with low or no carbon emissions (e.g., renewable or nuclear power generation); and (4) reducing emissions from EGUs as a result of use of demand-side energy efficiency. While the building-block methodology was developed to calculate state-specific performance standards in a consistent way, states are not even limited to relying upon the "building block" measures or approaches as the only ways to achieve compliance.

[9] Source: EPA. http://www2.epa.gov/carbon-pollution-standards/fact-sheet-details-about-proposal-new-sources.

[10] EPA's proposed rule for new fossil fuel-fired EGUs include: utility boilers, integrated gasification combined cycle (IGCC) units and certain natural gas-fired stationary combustion turbine EGUs that generate electricity for sale and are larger than 25 megawatts (MW). The rule does not apply to any existing EGUs or to units undergoing modifications or to reconstructed units. The rule also does not apply to liquid oil-fired stationary combustion-turbine EGUs; new EGUs that do not burn fossil fuels (e.g., those that burn biomass only); or low capacity-factor EGUs that sell less than one third of their power to the grid. http://www2.epa.gov/carbon-pollution-standards/fact-sheet-details-about-proposal-new-sources.

[11] Specifically, EPA has proposed standards of 1,000 pounds of CO_2 per MWh for larger units. Larger units are those with fuel input capacity greater than 850 million British Thermal Units per hour (mmBtu/hr)). For smaller units (those with fuel input capacity less than 850 mmBtu/hr), EPA has proposed a standard of 1,100 lbs CO_2/MWh.

[12] The proposed limits for fossil fuel-fired utility boilers and IGCC units are based on the performance of a new efficient coal unit implementing partial carbon capture and storage (CCS). EPA is proposing two limits

Taking into consideration both of these proposed regulations, states will have the option to choose whether to fold the new generating units into the program affecting existing sources once the new units go into operation or at some point after that. This is one of four types of flexibility that EPA's Clean Power Plan provides to the states as they design their plans. Because all of these forms have implications for whether a state plan aligns well – or poorly – with competitive markets, we describe them here and summarize them in Table 1.

Table 1
Sources of Flexibility in States' Design of their State Plans to Comply with EPA's Proposed Clean Power Plan

Source of Flexibility:	**Explanation:**
Form of the CO_2-emissions standard	A state may use a rate-based approach (lbs of CO_2/MWh from affected EGUs) or a mass-based approach (a total cap on CO_2 emissions from affected EGUs).
Spatial flexibility	A state may develop a common or different set of approaches to reducing CO_2 emissions at EGUs in different parts of the state, and they may enter into multi-state plans with neighboring and non-contiguous states.
Options for the content of Plan elements	A state may choose from a wide set of options to incorporate into their state's Plan.
Scope of units covered by the State Plan	A state may choose to fold new generating units into the system applied to existing units at some point after the new ones go into operation, or the state's plan may treat old and new units separately.

Form of the CO_2-emissions standard: EPA has proposed to allow states to translate the *rate-based* performance standard into a *mass-based* equivalent. That is, EPA has proposed default methods by which a state can translate the state's *rate-based* performance standard (in lbs of CO_2/MWh) into a *mass-based* total emission limit (in tons per year of CO_2 emitted from the portfolio of affected sources). States will also have the ability to propose an alternative methodology for converting the rate-based standard into an emissions cap affecting certain power plants.

for fossil fuel-fired utility boilers and IGCC units, depending on the compliance period that best suits the unit. These limits require capture of only a portion of the CO_2 from the new unit. These proposed limits are: 1,100 lbs CO_2/MWh-gross over a 12-operating month period; or 1,000-1,050 lbs CO_2/MWh-gross over an 84-operating month (7-year) period. http://www2.epa.gov/carbon-pollution-standards/fact-sheet-details-about-proposal-new-sources.

A recent report[13] examining these alternatives has further categorized the 'straw man' options as follows: three alternatives that use a mass-based approach and three others that use a rate-based approach. (See Table 2.) These different straw proposals also incorporate a second dimension of the flexibility that EPA has built into the Clean Power Plan: ***spatial flexibility***. States can design compliance plans that average emission reductions across separate units within the fence of a generation facility or across all generating units owned by a single company. Compliance obligations could also be bundled across companies within a state, or states can adopt multi-state approaches, for example, where integrated companies have operating subsidiaries that cross state lines, or where neighboring states operate within a single bulk power region or wholesale electricity market. Finally, a state with generating units in more than one RTO may develop different compliance approaches for those separate parts of the state and enter into two sets of multi-state plans.

A third source of flexibility relates to the ***options available to states as they shape their Plans.*** Elements of a State Plan could include reductions in tons emitted within the state by affected EGUs through such things as: requiring heat-rate improvements; incorporating permit limits on the operations of certain EGUs; retirement of particular EGUs; making adjustments in the transmission grid; reductions in demand for electricity in the state by operating the system at acceptably lower voltage levels; capacity upgrades at nuclear or hydroelectric plants; installing measures to use less water and thereby reducing electric-pumping requirements of water supply systems; and so forth.

Scope of units covered by the State Plan: Finally, and as noted previously, states may choose to develop state plans that address only *existing* EGUs, limiting new source requirements to the NSPS under Section 111(b). However, states may instead elect to wrap into the Clean Power Plan compliance scheme new resources as they come on line (or, alternatively, after some short period of initial operation). In such a case, new sources would be subject to the NSPS as part of their initial permitting requirements but then would also participate in a statewide program to address all emissions from EGUs – for example, in a mass-based cap-and-trade program covering all sources, with or without the cap expanded to include the emissions from the new units.

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[13] Franz Litz and Jennifer Macedonia, Choosing a Policy Pathway for State 111(d) Plans to Meet State Objectives, Great Plains Institute and Bipartisan Policy Center, April 24, 2015.

Table 2
Straw-Man Options for States to Design Mass-Based Versus Rate-Based Approaches to Limiting CO_2 Emissions from Electric Generating Units (Litz/Macedonia)

Form of CO_2 Emissions Standard	Straw Man Option	Explanation
Mass-Based Straw Man Approaches	"Utility Budget Approach"	"The state allocates shares of its mass-based state emissions budget to each utility (and other plant-owning entities). This allows the utility to then manage its budget of allowed tons across its entire fleet of affected electric generating units." The approach could be implemented in a single state or across multiple states.
	"Plant-Level Emissions Budget Trading Approach"	"A state starts with its allowed emissions budget, or the total number of tons that may be emitted from all of the affected electric generating units in the state for each year. Emissions allowances are issued by the state with each allowance representing an authorization to emit one ton of carbon dioxide. Affected electric generating units must track and report their covered emissions. At specified intervals, affected units must turn in sufficient allowances to cover their emissions." The approach could be implemented in a single state or across multiple states.
	"Utility Budget Approach with Optional Trading"	This would borrow from the other two mass-based approaches and would "allow utilities (and other plant-owning entities) the flexibility to meet an emissions budget across their fleets, and the option to participate in emissions trading with others that also choose to participate in trading. The approach could be implemented in a single state or across multiple states. States could create the infrastructure for trading to occur across state lines."
Rate-based Straw Man Approaches	"Utility Rate Approach"	"The state prescribes an emissions rate for each utility (or other plant-owning entity). Each utility then manages its fleet of covered power plants to meet the prescribed rate through actions at the plants themselves or activities like energy efficiency that avoid emissions at the plants through energy savings. The flexibility inherent in this approach is often referred to as 'bubbling' because it creates a figurative bubble over all of the utility's affected units, allowing the utility in the rate-based context to average the emissions performance across all of its affected units."
	"Rate-Based Trading Approach"	This one "entails applying a prescribed emissions rate to all affected units. An affected unit that generates electricity at an emissions rate that is lower than the prescribed rate will generate emissions credits. A unit that generates electricity at a rate that is higher than the prescribed rate will need to use credits to adjust its rate downward. In this way, units that exceed the prescribed emissions rate can continue to generate electricity as long as the generation is offset with credits. In effect, the emission rates are averaged across all units in the system and all unit owners."
	"Utility Rate Approach with Optional Trading"	This one borrows from the two other rate-based approaches and can "provide flexibility for owners and operators of affected electric generating units to achieve the prescribed emissions rate in a least-cost manner. A utility rate approach with optional trading would allow utilities (and other owners of power plants) the flexibility to meet an emissions rate across their fleets, and the option to participate in emissions credit trading with others that also choose to participate in trading. The approach could be implemented in a single state or across multiple states. States—ideally with EPA assistance—could create the infrastructure for trading to occur across state lines."

Source: Franz Litz and Jennifer Macedonia, "Choosing a Policy Pathway for State 111(d) Plans to Meet State Objectives, Great Plains Institute and Bipartisan Policy Center," April 24, 2015.

These multiple degrees of freedom allow for a great deal of discretion by states in designing their State Plans. And the many degrees of freedom within *and across* states create the potential to introduce new environmental regulations in a manner that either aligns EGU owners' and other market participants' incentives with the economic-efficiency goals of competitive electricity markets, or creates tensions between the two. As states consider their options, there are strong economic-efficiency arguments for taking into consideration the potential ramifications of different state-plan elements on creating unintended distortions in the competition among different power resources in the wholesale power markets that supply electricity to the state's consumers.

2. WHOLESALE ELECTRICITY MARKETS

Overview: Organized Wholesale Power Markets

The EPA's proposed carbon regulations will affect power plants that operate in many different contexts around the country. One key attribute of the electric industry that has developed over the past two decades is the existence of competitive wholesale markets.[14]

How states design their Clean Power Plans will either support or undermine least-cost compliance and the efficiency of competitive wholesale power markets.

Today, a significant portion of retail customers' power is sourced through wholesale supply. In some parts of the country (e.g., much of the South and the West), wholesale supply occurs through bilateral purchases and sales, and most of the power provided to retail customers comes from the local utility's own fleet of power plants. In other parts of the country, the primary framework for wholesale supply is a centralized wholesale market (also called an 'organized' wholesale market).

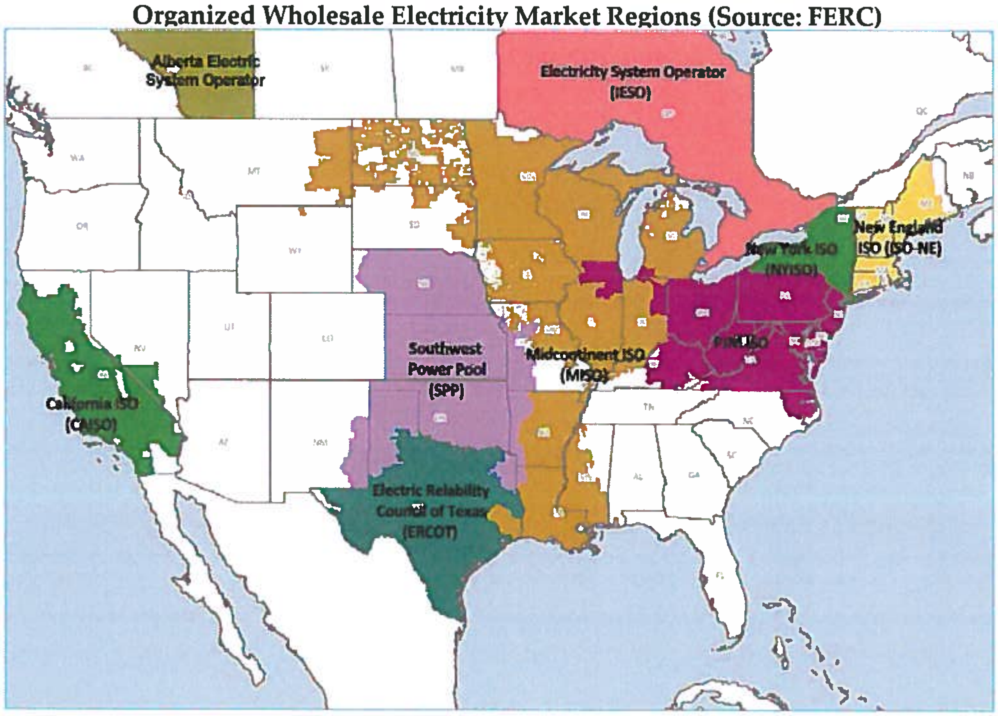
In an organized wholesale market, an RTO administers a bid-based central energy market with coordinated dispatch of all generating units in the footprint of the system.

[14] Historically (and even today), when a regulated utility owned a power plant whose output was for the benefit of that utility's own customers, the costs associated with that power plant were recovered directly in retail customers' rates regulated by state or local authorities. In such a case, there is no wholesale purchase or sale of power (i.e., no sale for resale), and the local regulator established the terms and conditions of cost recovery of capital costs and operating expenses in rates charged to end-use customers. When that power plant provided power for the benefit of another utility and its customers, that power sale occurred as a bilateral wholesale transaction, with prices subject to regulation of the Federal Energy Regulatory Commission (FERC). Traditionally, such transactions were priced at cost. That situation changed starting in the 1990s, when FERC began to evolve its policies to enable the electric industry to rely on competition (rather than cost-based regulation) as the means to set prices in transactions where the seller lacked market power. In the electric industry, "market power is the ability of an electricity supplier to raise prices profitably above competitive levels and maintain those prices for a significant time. Electricity suppliers exercising market power force consumers to pay higher electricity prices than they would pay in a competitive market." EIA, "The Changing Structure of the Electric Power Industry 2000: An Update," page 78.

In such organized markets, wholesale electricity is bought and sold at market prices based on that dispatch, under rules approved by the Federal Energy Regulatory Commission (FERC).[15] (See the Appendix for an explanation of the energy, ancillary service and capacity markets administered by RTOs in the U.S.)

These RTOs cover power plants in over two-thirds of the states, encompass 70 percent of the nation's generating capacity,[16] and meet the electricity requirements of two-thirds of the American people. As shown in Figure 1, the U.S. RTOs are the California Independent System Operator (CAISO), Electric Reliability Council of Texas (ERCOT), ISO New England (ISO-NE), Midcontinent Independent System Operator (MISO), New York Independent System Operator (NYISO), PJM Interconnection (PJM), and Southwest Power Pool (SPP).

Figure 1:
Organized Wholesale Electricity Market Regions (Source: FERC)



[15] RTOs are also responsible for the reliability of the transmission grid and for balancing generation and load at all times over the RTO's geographic footprint. RTOs conduct short-and long-term planning to ensure resource adequacy and transmission-system security, assure the provision of non-discriminatory access to the grid for owners of power plants, and provide for the design and administration of competitive wholesale electricity markets. All RTOs carry out their work with the input and advice of market participants and other stakeholders (including representatives of relevant state regulatory agencies).

[16] SNL Financial.

How Emission-Control Costs Factor into Asset Decisions and Offers in Competitive Wholesale Markets

Overview: Owners of non-utility power plants in wholesale markets recover emission-control costs in very different ways than traditionally regulated utility companies that own power plants in those markets (or in the parts of the country outside of an RTO footprint). Owners of merchant generating assets attempt to recover their costs in bilateral contracts with customers and/or utilities, or from the organized markets for capacity, energy and ancillary services. They may not be able to do so, however, depending upon competitive market conditions and other factors.

Notably, states' decisions about the design of their State Plans will alter the economics of competitors in wholesale markets. In an RTO market, the clearing price of power ($/MWh) reflects the offer price of the marginal generator dispatched to meet load in a particular hour (with the offer price typically reflecting that unit's variable operating cost, including fuel and emissions allowances). If the marginal generator is an existing EGU subject to the Clean Power Plan and had to purchase an emission allowance (under a mass-based approach) or an emissions credit[17] (in a rate-based emission-trading scheme) to cover its CO_2 emissions, the clearing price of power will go up, reflecting the carbon-intensity of that EGU. That clearing price would be paid to generators that are producing power in that hour, and a generator not dispatched (or not operating) in that hour would receive no energy payment.

From the perspective of electric energy markets, the design of CO_2-emission-control programs can have a number of different types of impacts on different plants, depending upon where they are in the supply stack and how the State's approach creates incentives for responses by an owner of a power plant. Some of those potential approaches – e.g., a market-based trading program – price compliance equally across competitors based on the direct carbon intensity of different EGUs and can be competitively neutral in energy markets (with the only change being the carbon-intensity of marginal generation). But other approaches may not. To highlight the differences among approaches, we describe market impacts of three potential compliance pathways.

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[17] Depending on the level of the lbs/MWh performance standard and the emission rate of the marginal generator, the operating costs of the unit may increase or decrease. If the unit emits above the level of the standard, its costs per MWh would increase. If the unit emits below the level of the standard, its costs per MWh would decrease because it earns a credit for each MWh of electricity it produces.

First example: an economically efficient plan for CO_2 compliance by EGUs in RTO states: Consider a situation in which some (or preferably all) of the states in an RTO elect to prepare and implement a multi-state, mass-based plan covering all of the EGUs – existing and new – in the footprint of the RTO into a single CO_2 program. The overall cap on emissions would be set at the sum of all of the participating states' mass-based emissions goals for those EGUs in that RTO.[18] All of the EGUs in the entire footprint of the RTO would face the same carbon price (in $/ton emitted), in the form of having to own or control an allowance to emit a ton of carbon.

In such a market, a relatively carbon-intensive EGU would face increased operating costs (in $/MWh), which might cause the plant to shift to a different (higher-cost) position on the dispatch stack. That impact might or might not cause it to be dispatched less often. For example, if the plant were a relatively efficient coal plant that remained an economical base-load EGU even after the purchase of emissions allowances, and the increase in operating costs did not cause it to be more expensive than the marginal generator in any hour, then it would not operate less often. Its operating costs would go up, but so would its revenues (because of the impact of having higher clearing prices in the market). By contrast, a less-efficient coal plant or gas-fired power plant which similarly had to purchase allowances to cover its emissions might end up operating less because its relative carbon intensity and inefficiency caused it to be more expensive in some hours than the marginal generator would be in the absence of the CO_2-control program. Overall, the system's re-dispatch would reflect efficient operations taking carbon costs into account. The overall electric system would be producing electricity with lower CO_2 emissions and an economic dispatch of competing sources of power with different carbon intensity.

Second example: an economically inefficient plan for CO_2 compliance by EGUs in RTO states: By contrast, let's assume that the same states adopt that same plan for existing units, but some of those states (the "A Group" of states) decide that they want to keep new NGCCs out of their states' program and other states (the "B Group" of states) decide to fold new NGCCs into the program that covers existing units. Finally,

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[18] In instances where a state has EGUs in different RTOs or has some power plants in an RTO and other EGUs not in an RTO at all, and where the state wants to adopt a state plan that differentiates compliance elements consistent with those electric-system constructs, then the state will need to establish the emissions targets for those EGUs in the RTOs. The state could do this, for example, by assigning the state's average rate-based emissions target to each EGU and then converting those amounts to a mass-based number for the EGUs in the RTO.

for the states (the A Group) that do not fold new NGCCs into their emissions-trading program, those new plants otherwise have no CO_2-emissions requirements beyond what they needed to obtain their original air permits under the NSPS program.

Would this combination of state plans lead to competitively neutral impacts and incentives in this RTO market, with the only adjustment reflecting the carbon intensity of EGUs? No. Here is why: Identical NGCC facilities in the same RTO would face different price signals, leading to market distortions and a suboptimal allocation of capital. Existing EGUs in the RTO (across the A and B Groups of states) would have to buy CO_2-emission allowances and include their value in offer prices into the RTO's energy markets. A new NGCC located in an A Group state and having a very similar CO_2-emissions profile (i.e., lbs of CO_2/MWh) as some of those existing EGUs in the RTO, however, would not have to. This means the *new* NGCC with essentially the same heat rate and operating cost as other *existing* EGUs would routinely dispatch ahead of others, increasing its output, its revenues, and its profits relative to other similarly situated EGUs. The new NGCC would also get the revenue benefit from higher clearing prices without incurring additional costs. This would give the new NGCC a competitive advantage over the other generators in the RTO due to state policy design and not because of any intrinsic cost advantage of the new NGCC.

Moreover, this advantage may actually induce new NGCCs to enter the market in one of the A Group of states. A new NGCC would have no such advantage if it were located in a state in the B Group. In fact, a proposal to site and permit a new NGCC in a B Group state would increase competition for the supply of CO_2 allowances for all EGUs in the RTO, increasing carbon prices and further aggravating the competitive inequities and market distortions created by the disparate policy approaches. The B Group states would have the strongest overall limit of CO_2 emissions from power production, shifting emissions to the states in the A Group.

An analysis performed by Calpine Corporation suggests that at certain levels of CO_2-emission-allowance prices, the advantage afforded to new units by A Group states (i.e., states that elect to allow a new NGCC to operate outside of the cap-and-trade program established for EGUs in the same state) could lead developers to anticipate high-enough revenues in future electric-energy markets to make it worthwhile to invest in the capital costs of a new power plant.[19] This state policy design could lead to more development of NGCCs and potential displacement of otherwise economical and low-emitting generating assets without a commensurate reduction in CO_2 emissions. It would lead to stranded costs at existing units, again, without a CO_2 benefit. Such an outcome would be antithetical to the principles of competitive electric markets and to sound CO_2-emissions-reduction policies.

Third example: another economically inefficient plan for CO_2 compliance by EGUs in RTO states: In this example, let us assume that the states with EGUs participating in the RTO market all decide to adopt a rate-based CO_2-emissions-reduction approach for those EGUs. This is similar to the "Rate-Based Trading" straw-man approach[20] described in Table 2, above.

The EPA's proposed Clean Power Plan has very different emission-rate targets across the states. In some cases, neighboring states within an RTO region have significantly different rate-based targets. Figure 2 shows the state-specific interim (2020-2029) rate-based targets for each of the 49 states with EGUs. States are ranked from highest to lowest in terms of the amount of CO_2 their targets would allow EGUs in their states to emit. The highlighted states have EGUs that are members of the PJM RTO. The range in targets among these states is between 1,844 lbs/MWh (for EGUs in Kentucky) to 647 lbs/MWh (for EGUs in New Jersey).

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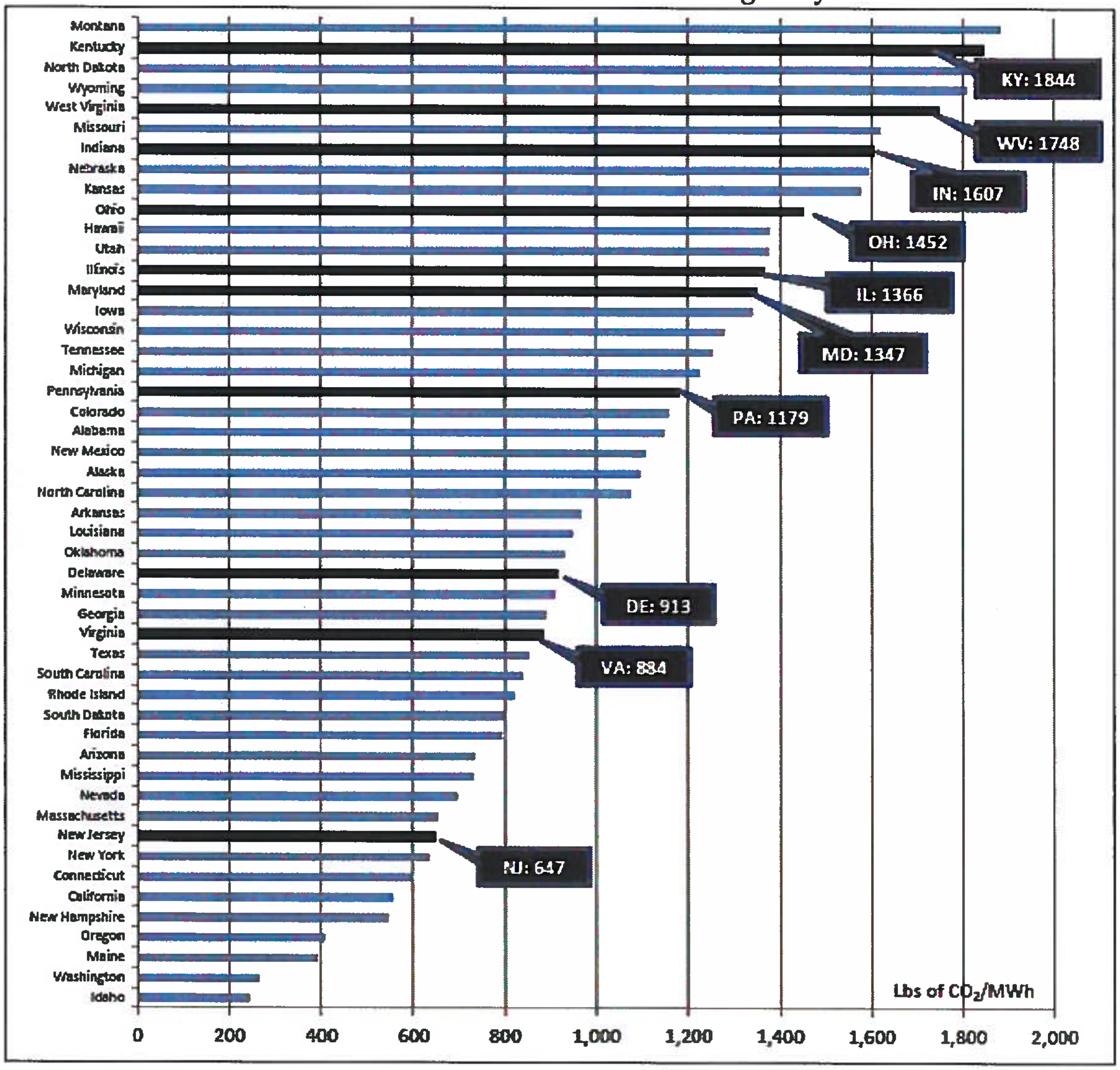
[19] Calpine's estimate is based on conditions in the PJM RTO market, where the all-in, levelized cost of new entry for an NGCC is $31/MWh. In this analysis, Calpine calculated that in the absence of a mass-based compliance plan covering all fossil units, an existing NGCC and a new one with equivalent heat rates and emissions rates would each have the potential to generate revenues in PJM's energy markets of $20/MWh above variable operating costs, so that these revenues would contribute to recovery of fixed costs of the power plants. With a mass-based compliance plan with CO_2-allowance prices equivalent to $30/ton, the impact on clearing prices and energy-market revenues for a new NGCC that did not need to acquire emissions allowances would equate to approximately $11/MWh. At this level ($20/MWh plus $11/MWh), the new NGCC would find it economically attractive to enter the market and compete with existing generators with exactly the same emissions profile. Thus, as a result of state policy, there would be new entry without any commensurate reduction in CO_2 emissions. Calpine Corporation, "The Impacts of the Clean Power Plan on Wholesale Power Markets." February 24, 2015.

[20] This approach "…entails applying a prescribed emissions rate to all affected units. An affected unit that generates electricity at an emissions rate that is lower than the prescribed rate will generate emissions credits. A unit that generates electricity at a rate that is higher than the prescribed rate will need to use credits to adjust its rate downward. In this way, units that exceed the prescribed emissions rate can continue to generate electricity as long as the generation is offset with credits. In effect, the emission rates are averaged across all units in the system and all unit owners." Source: Franz Litz and Jennifer Macedonia, "Choosing a Policy Pathway for State 111(d) Plans to Meet State Objectives, Great Plains Institute and Bipartisan Policy Center," April 24, 2015.

Figure 2
Interim Period (2020-2029) Rate-Based Targets by State



Source: EPA. http://www2.epa.gov/carbon-pollution-standards/clean-power-plan-proposed-rule-technical-documents-spreadsheets

Let us assume that Pennsylvania, New Jersey, Ohio, and Virginia all decide to adopt a rate-based trading approach. Under EPA's proposal, each state could elect to keep its own CO_2/MWh rate or create a blended average CO_2/MWh rate across the other states, adopting a common multi-state, rate-based approach. Let us assume further that Pennsylvania and Ohio fold new NGCCs into their systems for existing units, while Virginia and New Jersey do not.

In this scenario and before the Clean Power Plan, the NGCCs would have similar offer prices and each would have a similar opportunity to be dispatched in the RTO's energy market. But under a Clean Power Plan scenario in which the four states retain their separate rate-based targets, there would be distortions in the PJM power market. The NGCCs located in Ohio and Pennsylvania would have the ability to generate an emissions-reduction credit for every MWh they generate because those NGCCs' emissions (assumed to be 1,000 lbs of CO_2/MWh) are below each of those state's target emissions (Ohio at 1,452 lbs/MWh and Pennsylvania at 1,179 lbs/MWh).

Thanks to those generated emissions-reduction credits, the Ohio and Pennsylvania NGCCs would be able to offer a lower price into PJM's market than the NGCCs located in New Jersey and in Virginia, with the latter actually having to purchase emissions-reduction credits because their emissions (at 1,000 lbs/MWh) are higher than those states' target rates (Virginia at 884 lbs/MWh and New Jersey at 647 lbs/MWh). The NGCCs in Ohio would be able to create the most credits (because their emissions targets are highest) and their compliance costs would be cheaper than an identical unit in Pennsylvania, which would further distort the dispatch stack. A New Jersey NGCC would be the most disadvantaged, and a NGCC in Ohio would be most advantaged. A new NGCC would be particularly attracted to locating in Ohio or Pennsylvania and could displace output in the other states *without any commensurate reduction in total CO_2 emissions*. Further distortions would occur if additional PJM states also adopted rate-based trading programs or mass-based trading programs (e.g., Maryland and Delaware are part of the RGGI program and part of PJM).

Insights from the examples: State CO_2 plans can – but do not need to – create distortions in wholesale power markets

As these examples show, the design of emission-control programs can affect similar generating facilities in distinctly different ways, either increasing or decreasing their operating costs within the same wholesale power market. Consequently, depending on the form of emission-compliance requirements, these requirements can affect clearing prices (upward or downward) in energy markets. The character of emission-control requirements can also affect a particular generating unit's net energy-market revenues because that unit may be dispatched more or less often than without those requirements, its own costs may change, and the clearing prices it receives may be different.

These various impacts mean that the design and administration of a new environmental regulation can create competitive advantages and disadvantages for different power plants (and varying financial impacts on the owners of different plants) without creating a clear or reasonable nexus between the differences in wholesale market impacts and the purpose of the regulation.[21] This, of course, tends to impact power plant owners' attitudes about whether the new regulation is a good idea or not and about what the appropriate design of the regulation should be. But it can also affect the ultimate economic efficiency of wholesale market operations (for example, by improving or harming heat rates or by facilitating or impeding dispatch of power plants across the states in a common RTO market). These inefficiencies would lead to adverse impacts on consumers.

To the extent that a state seeks to design a State Plan with neutral effect on the functioning of competitive power markets – i.e., enabling them to produce and deliver power efficiently and reliably and produce cost-effective CO_2-emissions reductions – the State Plan should focus on an approach that treats similarly situated competitors in a common regional power market in similar ways, with all of them facing an incentive to control carbon emissions as economically as possible.

If states in a single RTO do not coordinate the development of their State Plans, and their individual plans differ in significant ways, power plants in that market with the same – or very similar – technology, fuel, power-production efficiency and emissions rate will likely end up with quite different dispatch profiles only by virtue of the fact that they are located in different states, and without any lower CO_2 emissions.

The complex interactions between compliance requirements and how such requirements flow through wholesale markets – with consequences for unit operations, unit additions and retirements, unit costs, and consequently offers in competitive wholesale energy, ancillary service and capacity markets – have important implications for wholesale market outcomes. While the complexity of these various potential combinations of circumstances within and across states may make it seem as if a workable solution is untenable, just the opposite is true. The answer or solution is fairly straightforward: program designs that increase the uniformity of compliance-cost price signals – across

[21] This fact is not unique to environmental regulations: This also occurs when other public policies differentially affect plant investment and operations: a plant with a large workforce will face large financial impacts of a law changing labor compensation or worker safety issues; a plant with a larger land area will face a bigger impact if there is a change in property tax; and so forth. Also, changes in fundamental market conditions (e.g., changes in the relative prices of fuels like natural gas and coal) can – and do – introduce these differential impacts on power plants as well.

That outcome would be good for electricity consumers.

It will help if EPA and the states develop strategies that support alignment of carbon-emission controls with competitive market outcomes.

3. ALIGNING STATE PLANS WITH POWER MARKET STRUCTURES: CREATING INCENTIVES FOR LOWEST-COST CO_2 COMPLIANCE AND EFFICIENT POWER MARKET OUTCOMES

To support economically efficient compliance approaches along with economically efficient wholesale power market outcomes, states should adopt State Plan elements that encourage EGU owners to make economically rational decisions. Such decisions include whether to invest in and/or make operational changes to reduce a generating unit's emission rate (if the emission rate is above the state's performance standard); retire the affected unit(s); increase output and overall plant utilization (if the emission rate is below state performance standard); obtain and surrender emission allowances (at some incremental opportunity cost) for each ton of CO_2 emitted; or pay directly or indirectly for investments in energy efficiency and/or zero-carbon energy resources to achieve reductions in emissions.

EPA's Clean Power Plan proposal has given the states broad discretion about how to design their compliance plans. Ideally, states will elect to adopt plans that align with the character of the electric industry structure affecting EGUs in different parts of their states. This would mean that in regions with organized multi-state wholesale power markets, states would proactively work with their counterparts in the region to develop a common multi-state approach with similar core elements.

Why States Should Care About Aligning their CO_2 Compliance Plans with Wholesale Electric Market Structure

Recall that the motivation for restructuring the electric industry in many states and regions was that electricity supply could be provided more efficiently through markets than through traditional cost-of-service regulation.[22] Changes in the industry structure

[22] The long-standing goal of cost-of-service regulation of electricity supply has always been to mimic the incentives produced in competitive markets through properly structured regulation. In theory, a regulatory structure with such incentives to minimize cost and to incent innovation and good customer service will provide for the efficient development and operation of generating facilities, meeting consumers' electricity needs at the lowest possible long-run costs. With the advent of potential competition in markets for power generation in recent decades, many states moved to restructure their electric industries. At the same time,

coincided with significant changes in federal and state regulation of power plant emissions, which began to rely on market-based mechanisms as the way to meet environmental goals at lowest cost.[23]

As noted previously, the national experiment with the SO_2 cap-and-trade program has been widely viewed as a success for industry, states and EPA, and for consumers. This market-based framework has provided emissions reductions that took advantage of the innovative and cost-minimizing attributes of markets at significantly lower cost than had been expected.

The design of the SO_2-emissions-trading program has since been replicated in numerous federal, regional and state programs in the U.S. and abroad. Notably, there are numerous examples of multi-state cooperation on market-based environmental programs, where such has been allowed under law.

A prime example of a multi-state market-based program is the "NO_x SIP Call" program to reduce emissions of NO_x. That program had its roots in the efforts of the member

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structure with such incentives to minimize cost and to incent innovation and good customer service will provide for the efficient development and operation of generating facilities, meeting consumers' electricity needs at the lowest possible long-run costs. With the advent of potential competition in markets for power generation in recent decades, many states moved to restructure their electric industries. At the same time, states and regions where industry restructuring took hold moved to create independent entities (today's RTOs) to ensure fair access to the transmission grid and administer open, competitive markets for electricity supply. As previously discussed, the end result of these efforts is the competitive wholesale market structures and entities that exist throughout much of the country. The benefits of markets flow from moving investment and operational *risks* to those entities most capable of managing them and from the pressure to reduce *costs* and improve quality in order to succeed and profit from market activities. In a competitive market environment, pressure on market participants drives the industry to the lowest-cost, most-efficient responses to changing customer needs. In the electric industry, this drives down wholesale supply prices for electric ratepayers.

[23] Similar economic incentives, principles, and responses are at work in the design and implementation of market-based allowance-trading programs for control of power-plant emissions. As noted previously, some environmental laws and regulations do not allow for market-based approaches and rely on unit-specific technology-based pollution-control requirements, with significant administrative processes to administer and enforce these standards. This approach is in some ways similar to the challenges of traditional public utility regulation with prudency reviews: Air quality regulators attempt to determine administratively what will be the most effective, "best-available-control-technology," lowest-cost way to achieve air-quality objectives, and establish requirements for individual power-plant owners based on this evaluation. But as in the case of utility regulation, there are often practical constraints (e.g., limited or imperfect information, work force and budget restrictions) on the ability of air regulators to do their jobs. Given these challenges, the traditional unit-/technology-based air-quality framework is often viewed as a poor substitute for more market-based and direct emission cap or pricing regimes, with emission-reduction solutions driven by the decisions of market participants and priced by competitive market outcomes.

states of the Ozone Transport Commission (OTC)[24] to adopt a region-wide budget (or limit) on NO_x emissions. To control NO_x emissions that move across state boundaries, the OTC states developed a multi-jurisdictional cap-and-trade program. The resulting OTC NO_x Budget Program was the first cap-and-trade program formed by a group of states and represents the first large-scale application of the cap-and-trade model to a problem other than acid rain. Eventually, EPA expanded the number of states that needed to address inter-state transport of NO_x emissions through State Implementation Plans (through the so-called "NO_x SIP Call"), and provided a model rule that states could elect to adopt to carry out an inter-state program.[25] Eventually, all of the states opted into the multi-state emission-trading program.[26]

Notably, the NO_x SIP Call has parallels to today's situation with the proposed Clean Power Plan. The multi-state nature of the ozone and NO_x-emissions issues and of the industrial- and power-generation activities that contributed to the region's air quality problem lent itself to a regional solution. EPA acted to control a source of air emissions that had impacts beyond state borders and had to use the State Implementation Plan mechanism to do so. Individual states had the ability to develop a plan with command-and-control elements to accomplish their emissions-reduction targets. But every state eventually exercised its jurisdictional discretion to adopt a multi-state plan and to rely

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[24] The OTC was established in the CAA Amendments of 1990 as a means to help states in the Northeast work together to reduce emissions that affected the entire region's air quality. Members of the OTC include the District of Columbia and 9 states (Delaware, Maryland, Pennsylvania, New Jersey, New York, Connecticut, Rhode Island, Massachusetts, and New Hampshire) whose unhealthy air quality was affected by the transport of emissions across state boundaries. http://www.epa.gov/captrade/documents/nox.pdf.

[25] "The NO_x Budget Program set a regional 'budget' (or cap) on NO_x emissions from electric power generating facilities and industrial boilers from a variety of industry types during the 'ozone season' (from May 1st through September 30th) beginning in 1999.... To meet the budget, sources were required to reduce emissions significantly below 1990 baseline levels, and could use emissions trading to achieve the most cost-effective reductions possible. At the end of each ozone season, sources must demonstrate that their actual ozone season emissions do not exceed the amount of allowances held for that period. Unused allowances may be sold or banked for use in a subsequent ozone season. Regardless of the number of allowances a source holds, it may not emit at levels that would violate other Clean Air Act or state requirements. As with any cap and trade program, sources can devise their own strategies to comply with NO_x emission restrictions. The ability to trade allowances places a value on emission reductions and encourages sources to develop the most cost-effective emission reduction strategies to achieve the overall required emission reductions. This approach allows the OTC states to achieve greater reductions than could be captured under a traditional regulatory approach for the same overall cost."
http://www.epa.gov/captrade/documents/nox.pdf

[26] Eventually, the program included not only the original OTC states, but also parts or all of Missouri, Illinois, Michigan, Indiana, Ohio, Kentucky, West Virginia, Virginia, Tennessee, North Carolina, South Carolina, Georgia, and Alabama.

on a market-based approach to create incentives for minimizing the overall cost of compliance.

Similar motivations led to the development of the RGGI program, in which an original group of 10 states sat down together to develop their own common approach to reducing CO_2 emissions from power plants within their borders. The states reserved for themselves the ability to join the program – or not – and to adopt a framework that would allow for cost-effective emissions reductions. Although the states' memorandum of agreement allowed each state to choose the manner in which it would distribute allowances to affected power generating companies, the states eventually chose to establish a program where there was little variation in the states' implementation of the program. [27] Eventually, all RGGI states joined into a central auction process as a means to distribute allowances into the market and to establish the value of allowances.

The RGGI program is yet another example of a market-based emissions program that has accomplished emissions reductions cost-effectively and in a manner that allows for seamless implementation in centralized wholesale power markets.[28] The program is competitively neutral and affects the market only to the degree that a fossil-fuel power plant has to obtain allowances to cover its CO_2 emissions (if dispatched) and to build the value of those allowances into its offer prices in RTO markets.

Market-based emissions-control programs like these provide critically important lessons for EPA and the states as they move towards implementation of Clean Power Plan requirements. Most importantly, the past two decades have demonstrated the natural fit of market-based emission control approaches with competitive wholesale power markets and the ability of these structures to support fair and efficient electricity market

[27] RGGI was a first-of-its-kind CO_2 multi-state program with no prior framework. The states were able over the course of just several years to work together to: (1) design the program with a focus on market-based mechanisms and efficient design; (2) create the administrative rules, structures and organizations needed as a region (e.g., RGGI Inc., an allowance trading platform, organizational bylaws and governance, market monitoring procedures, etc.) and within states; (3) address the concerns, comments and perspectives of affected entities and stakeholders; (4) create a state model rule; (5) *agree upon the allocation of a regional budget amongst states* without having state-specific targets (as will be provided in the Clean Power Plan) and despite fundamental allocation decisions that had very real financial implications for states and states' asset owners; and (6) implement enabling state rules, regulations and laws with full administrative proceedings in each individual state.

[28] See, for example: Paul Hibbard, Susan F. Tierney, Andrea M. Okie, Pavel G. Darling, "The Economic Impacts of the Regional Greenhouse Gas Initiative on Ten Northeast and Mid-Atlantic States: *Review of the Use of RGGI Auction Proceeds from the First Three-Year Compliance Period*, November 15, 2011; and Paul Hibbard, Andrea Okie and Susan Tierney, "EPA's Clean Power Plan: States' Tools for Reducing Costs and Increasing Benefits to Consumers," July 14, 2014.

outcomes while minimizing the costs of achieving mandated emission control requirements. Absent this approach, conflicting and disjointed emission-control incentives from balkanized state implementation will likely increase the cost of the Clean Power Plan and diminish equity and efficiency in existing wholesale power markets.

Benefits of Market-Based Approaches in States' Clean Power Plans

In its proposed Clean Power Plan, EPA has recognized many elements supporting the states' ability to adopt plans that rely on market mechanisms and to establish these plans in ways that respect the regional nature of power production in most parts of the U.S.

Under Section 111(d), EPA must give states the ability to craft their own plans to comply with their emission-reduction targets. But beyond that, EPA has given the states the option to develop multi-state plans that align with the geographic realities of interstate wholesale power markets. This is an opportunity that invites states to afford themselves of the benefits of regional collaboration and market-based environmental strategies.

There are many benefits of adopting common market-based compliance plans that align well with competitive markets and avoid the potential for market distortions that could arise through inconsistent and uncoordinated state plans.

Ideally, such a system would have states individually electing to adopt a common framework that includes a mass-based cap covering a multi-state region, providing for emissions-averaging across the footprint of the system as a whole and folding in new units into the system as soon as they enter commercial operation (or shortly thereafter).

The benefits of such an approach include:

- *Economic efficiency of power supply*: A multi-state regional power market with an aligned multi-state CO_2 emissions program would create transparent price signals and appropriate economic incentives to owners of generating resources and suppliers of demand-side services to provide electricity services as efficiently as possible, taking into account carbon emissions and avoided carbon emissions. Such a system would allow for the translation of a marginal cost of compliance – the cost to emit the next ton of CO_2 – into part of the variable cost of electricity to be included in offer prices into wholesale electricity markets. This permits the grid operator to continue to implement economic dispatch of electric resources on a fair and efficient basis across all resources – regardless of fuel, age, or efficiency. This expands the universe of compliance options to include not only trading of emission-reduction opportunities across affected sources, but also the "trading" of emission reduction opportunities across affected and non-emitting sources (e.g., hydro, other renewables, nuclear, energy efficiency). Expanding the options for compliance will reduce the total costs of compliance relative to the alternative. A multi-state compliance program would also reduce the market distortions and unintended outcomes that may result from a patchwork of different state programs.

- *Lower-cost compliance*: As noted previously, experience with market-based emissions-trading approaches indicates that overall environmental compliance costs of emissions-trading programs are lower than original estimates and lower than alternative command-and-control programs. Recent modeling of multi-state market-based approaches indicates the economic advantages of such an approach relative to single-state and/or non-market-based approaches from a cost-of-compliance point of view. Such modeling has been conducted by the Bipartisan Policy Center, for example,[29] and by PJM with inputs from state regulators on the set of scenarios to analyze.[30]

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[29] Modeling by a team from the Bipartisan Policy Center (BPC) reached a number of conclusions, including these (quoted from the BPC presentation):

- The magnitude of impacts from the Clean Power Plan (CPP), including potential compliance costs, are dependent on EPA and state decisions yet to be made, as well as market factors, such as: the availability of end-use energy efficiency (EE); the price of natural gas, and the future of existing nuclear plants. This uncertainty increases the value of policy designs that inherently create the incentives for implementing least-cost solutions and allow affected companies flexibility to adapt to changing circumstances.
- Interconnected nature of the power system is important to consider when looking at costs and impacts of Clean Power Plan
- Benefits of multi-state collaboration and/or linked trading approaches: Adopting policy designs that allow access to emission reduction opportunities in other states tends to significantly lower the cost of compliance and reduce retirements.
- State choice of energy efficiency policies will significantly impact the cost: Effective end-use energy efficiency policies are important for cost containment. Demand reductions dramatically reduce system cost because they both reduce the need for additional capacity and lower fuel costs due to reduced demand.
- Treatment of new builds is an important policy consideration: Including new sources in implementation policies reduces potential market distortions and tends to lower cost; Different implications depending on state choice of rate-or mass-based goals.
- State policy choices will impact generation mix, investments, cost, and CO_2 emissions. Choice of rate- or mass-based goals and implementation policies: Mass-based implementation tends to lower total cost, while rate-based implementation has less impact on wholesale electricity prices. Despite projected wholesale electricity price increases in some states/scenarios, end-use EE may keep customer bills from increasing. Mass-based policies limit generation shifts and emissions leakage between states.

- ***Reliability***: A common multi-state market-based program will provide the system operator with maximum flexibility to continue to operate the system with security-constrained economic dispatch, taking into consideration the carbon intensity of power sources as well as the essential reliability services needed to maintain the integrity of the grid. The character of the multi-state market will act as a form of Reliability Assurance Mechanism and complement the reliability tools available to the grid operators.[31]

Jennifer Macedonia, Blair Beasley, Tracy Terry, Meghan McGuinness, and Stuart Iler, "Insights from Modeling the Proposed Clean Power Plan," Bipartisan Policy Center, April 2015.

[30] PJM recently conducted analyses of the changes in system-wide production costs assuming various designs of states' compliance plans. Quoting from the PJM report, the "high-level insights from the economic analysis include:

- Fossil steam unit retirements (coal, oil and gas) probably will occur gradually. As the CO_2 emission limits decline over time, the financial positions of high-emitting resources should become increasingly less favorable, with lower-emitting resources displacing them more often in the competitive energy market.
- Electricity production costs are likely to increase with compliance because larger amounts of higher-cost, cleaner generation will be used to meet emissions targets.
- The price of natural gas likely will be a primary driver of the cost of reducing CO_2 emissions if natural gas combined-cycle units become a significant source of replacement generation for coal and other fossil steam units.
- Adding more energy efficiency and renewable energy and retaining more nuclear generation would likely lead to lower CO_2 prices; this could result in fewer megawatts of fossil steam resources at risk of retirement because lower CO_2 prices may reduce the financial stress on fossil steam resources under this scenario.
- State-by-state compliance options, compared to regional compliance options, likely would result in higher compliance costs for most PJM states. This is because there are fewer low-cost options available within state boundaries than across the entire region. However, results will vary by state given differing state targets and generation mixes. PJM modeled regional versus individual state compliance only under a mass-based approach.
- State-by-state compliance options would increase the amount of capacity at risk for retirement because some states likely would face higher CO_2 prices in an individual compliance approach."

"PJM Interconnection Economic Analysis of the EPA Clean Power Plan Proposal: Executive Summary and Frequently Asked Questions" March 2, 2015, included as an attachment to the statement of Michael J. Kormos, Executive Vice President – Operations, PJM Interconnection, before the Federal Energy Regulatory Commission, Docket No. AD15-4-000, "Technical Conference on Environmental Regulations and Electric Reliability, Wholesale Electricity Markets, and Energy Infrastructure," March 11, 2015.

[31] We discuss such tools in our papers: Susan Tierney, Paul Hibbard and Craig Aubuchon, "Electric System Reliability and EPA's Clean Power Plan: Tools and Practices," February 2015; Susan Tierney, Paul Hibbard and Craig Aubuchon, "Electric System Reliability and EPA's Clean Power Plan: The Case of PJM," March 16, 2015; and Susan Tierney, Eric Svenson, Brian Parsons, letter and report to Chairman Norman Bay, FERC, re: Ensuring Electric Grid Reliability Under the Clean Power Plan: Addressing Key Themes from the FERC Technical Conferences, Docket No AD15-4, April 17, 2015.

- *Administrative simplicity and efficiency for assuring compliance:* While the initial set up of emission- and allowance-tracking systems requires an up-front expense, a cap-and-trade program is easier to administer than a program implemented through unit-by-unit control technology and unit-specific permit restrictions. Economic incentives built into the program to ensure that an EGU's emissions are covered by the surrender of a sufficient number of allowances (and with financial penalties for failure to do so) support ease of administration. The transparency of the emissions-trading system and of the performance of the system as a whole avoids the administrative complexity of measurement and verification systems associated with energy efficiency programs. From the point of view of the energy-efficiency measures' impacts on carbon emissions of the system, those impacts end up being embedded into the outcomes of the dispatch of the electric system. The same is true for incorporating the value of zero-carbon generation, as well. "A mass-based approach captures all emissions reductions that occur at the covered plants, whatever the reason for those reductions, without the need to design and implement a crediting mechanism for those reductions. Importantly, reductions can be captured from activities or events that EPA or a state might not allow a state to credit in the rate-based context, or that may be difficult to credit."[32]

- *Equity:* Such a system would treat all emitting units – new or existing, efficient or inefficient, coal or gas – fairly from the point of view of their CO_2-emissions compliance burden by subjecting them on the margin to the same emissions-reduction cost per ton of emissions, thus enabling the accomplishment of the overall emissions-reduction goal at the lowest overall cost.

- *Environmental integrity:* Once emissions caps are established, the system's performance can be met, verified, and enforced. Continuous emissions

[32] Franz Litz and Jennifer Macedonia, "Choosing a Policy Pathway for State 111(d) Plans to Meet State Objectives," April 14, 2015. http://bipartisanpolicy.org/wp-content/uploads/2015/05/Policy-Pathways-Paper.pdf. The authors say further that in a rate-based approach, "In order to credit emissions reductions or avoided emissions that result from activities outside the fence line of power plants—such as through energy efficiency or renewable energy projects—a state must design and implement a crediting mechanism for each type of credit. This is the biggest administrative challenge in the ratebased context that does not exist in the mass-based. Some eventualities that reduce emissions may not affect the emissions rate, such as plant retirements or when demand is reduced for reasons that cannot be credited. In addition, some have raised concerns that credits and the crediting process can be legally challenged, including through citizen suit actions."

monitoring leads to highly accurate emissions monitoring. Emitters are generally motivated to comply by punitive sanctions if they fail and/or by requirements to make up for excess emissions at some multiple above exceedances.

In sum, and most importantly from the perspectives of market impacts and consumer costs, emissions-cap and allowance-trading programs drive lowest-cost emission reduction outcomes. They can be seamlessly integrated into competitive wholesale power market mechanics in a fair and efficient way. Carrying out such programs through cooperation among states in a regional RTO market will support those regions' continued co-optimization of cost and reliability outcomes.

4. CONCLUSION

We strongly encourage states with electric generating units in organized wholesale power markets to coordinate the development of state plans so that they can elect to participate in a common, mass-based multi-state emissions-trading program that covers both existing EGUs and new NGCCs as they enter the market over time.

We encourage states with EGUs in RTO markets to adopt a mass-based emission-trading program that covers both existing and new NGCCs in the footprint of the RTO. And we encourage EPA's final rules to include incentives for states that adopt such approaches.

We hope that states will decide for themselves that this is the pathway toward a least-cost compliance strategy for CO_2 emissions reductions and an efficient, reliable power system for the benefit of their consumers.

In saying that, we do not mean to suggest that states would decide to eliminate other energy programs affecting the power sector, including renewable portfolio standards, energy efficiency programs, clean energy standards, or other policies. We think that a well-designed multi-state mass-based system dovetails with these other policies, and we note and respect the findings of so many analysts (including our own work) that indicate that overall cost of compliance will be lower with energy efficiency as a lead strategy.

Although we do not expect that EPA's final rule will impose a requirement that states adopt the type of multi-state, mass-based plan we urge them to support, we nonetheless encourage EPA to provide even greater incentives for states to adopt mass-based approaches that consolidate new NGCCs into their program for existing generating units.

Consistent with comments filed by many parties in EPA's rulemaking docket for 111(d) and/or 111(b), there are many examples of provisions that EPA could incorporate in the final rules (and/or preamble) to encourage states to move in this direction, including:

- Provision of a default/presumptive mass number for each state expressed alongside the rate target.

- Streamlined review of State Plan submittals that include a multi-state mass-based program covering generating units that operate in an RTO, including release from a requirement to submit a plan revision with each new NGCC that enters operation in the state or release from a requirement to adopt a memorandum of understanding with other states with a mass-based approach in order to trade with them.[33]

- Preparation of a model rule or a national tracking system/platform that would allow for the creation and trading of CO_2 emission allowances and/or emissions-reduction credits.[34]

- Providing states more time to submit their States Plans if they can show that they are working toward the development of a multi-state approach.

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[33] Comments of Calpine Corporation: "The New Source/Existing Source Coverage Gap is Potentially the Most Significant Shortcoming of the Proposed Clean Power Plan.....Failure to address this gap in coverage could result in serious market distortions and higher costs for ratepayers than are necessary to achieve the Proposed Rule's goals. ...EPA's publication of presumptively approvable mass emissions budgets that include new sources is a positive step in the direction of incenting states to cover new sources in their state plans. EPA should do all it can to encourage states to cover new sources in their state plans." Calpine Corporation Comments on the Proposed "Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units," Docket ID No. EPA–HQ–OAR–2013–0602, page 4.

[34] Comments of the Clean Energy Group: "We urge EPA to support the development of credit markets for 111(d) compliance. Such markets should function similar to existing [renewable energy credit] REC markets, which verify and track credits to avoid double counting, and states may elect to utilize the existing REC market as a component of their compliance plans to the extent that RECs have equivalent attributes. We recommend that EPA issue guidance for state plans that clarifies the use of compliance markets as a part of state plans. For example, we expect that some states may be interested in submitting partial joint plans that reference the use of a national 111(d) energy credit for compliance without entering into memoranda of understandings with each state that might be a generator or purchaser of renewable energy credits, and EPA should ensure it does not create a barrier for this compliance option. If requested by states, EPA may also want to consider developing a national tracking system for 111(d) compliance credits to facilitate this multi-state dynamic." Clean Energy Group Comments on the Proposed "Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units," Docket ID No. EPA–HQ–OAR–2013–0602 (hereafter "Clean Energy Group comments"), page 11.

- Introduce detailed administrative requirements, accounting rules, and 'burdens of proof' in instances where a state builds a plan based on a rate-based approach and wants to trade emissions-reduction credits from a state with a mass-based approach, and vice versa.[35]
- Clarify the value of a mass-based approach that coincides with the borders of RTO regions as an explicit tool for assuring electric system reliability.
- Provide a disincentive for a rate-based state backsliding on existing zero-carbon resources that are not factored into the rate target, in light of the consequences for overall CO_2 emissions with loss of such resources.
- Address the concern of some observers that a mass-based approach constrains growth, perhaps through allowing a protocol to adjust the mass-based cap with the addition of new generating units satisfying NSPS, or explaining how the addition of energy efficiency or zero-carbon resources adds no emissions but reduces price pressure on emissions allowances.

[35] Exelon Corporation's comments suggest various accounting rules to accompany trades among EGUs in states with dissimilar emissions-reductions schemes. Such "rules are designed to count each emission reduction once and only once and can also be summarized as a set of eight accounting rules:

1. When a mass-based state sells a CO2 allowance, the selling state's generators must reduce their emissions by one ton.
2. When a mass-based state buys a CO2 allowance, the buying state's generators may emit one more ton of carbon.
3. When a rate-based state buys a CO2 allowance, the buying state may deduct one ton of carbon from the numerator of its compliance calculation.
4. When a rate-based state sells a REC, the selling state may not take credit for the REC or the underlying zero-carbon generation.
5. When a mass-based state that does not use allowances sells a REC, the selling state must reduce its emissions budget by 0.5 tons (assuming that the mass value of a REC is 0.5 tons of CO2).
6. A mass-based state that uses allowances may not sell a REC to be used for Clean Power Plan compliance in another state."

Exelon Corporation, Comments on the Proposed "Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units," Docket ID No. EPA–HQ–OAR–2013–0602, page 103.

In sum, we encourage EPA and the states to:

- Seek consistency in the design of Clean Power Plan compliance approaches across states within integrated wholesale market regions. The broader the geographic scope of compliance, the more efficient, lower cost, and more reliable the outcome.

- Seek consistency in the manner in which the burden of CO_2-emissions reduction falls on different classes of units: as much as possible, encourage the creation of a system that is blind to age and type of generating technology, and instead assigns a consistent compliance cost per unit of energy produced so that the social costs of compliance are minimized.

With such principles, there is much greater likelihood of outcomes beneficial to consumers: efficient electricity markets and efficient environmental-compliance approaches.

APPENDIX: PRIMER ON ORGANIZED WHOLESALE POWER MARKETS

The specific design of electricity markets across the RTOs varies somewhat, but in all of them, the pricing for electric energy (in MWh) is established based on the offer price of the marginal generating unit dispatched to meet load at a particular time (e.g., an hour). This is called the clearing price. Owners of power plants tend to offer their electric energy supply at a price that roughly reflects their costs of operation. Essentially, the clearing price is paid to all generators that are dispatched to provide physical supply of power, and generators that are not 'cleared' (selected) receive no compensation in the energy market in that time period.[36]

In terms of longer-term signals to spur investment when needed, certain RTOs (ISO-NE, NYISO, and PJM) administer fully competitive auctions for procuring capacity. Other RTOs (CAISO, MISO) have a hybrid system combining market procurement of capacity with self-supply obtained through ownership or bilateral contracts. ERCOT and SPP have no capacity markets. In all regions, the RTOs procure a variety of things (called ancillary services[37]) needed for reliable system operations through some mix of market-based and non-market mechanisms.

[36] In practice, RTOs tend to have "day-ahead" and "real-time" markets for energy. Most binding financial commitments are made in the day-ahead market, whereby generating asset owners offer to supply energy at specified prices in each hour of the subsequent day. If selected to operate – or "committed" – a resource is paid in each hour of the next operating day based on the offer of the last (marginal) unit selected to operate in that hour to cover energy demand. Real-time markets settle out differences between load and generation close to real time throughout the operating day (e.g., if load is higher or lower than expected in the day-ahead market).

[37] Ancillary services include a variety of products and services (e.g., spinning reserves, automatic generation control, regulation service, black-start service). Typically they can be supplied by certain dispatchable loads and/or power plants with certain operational characteristics (e.g., fast-start and ability to ramp up or down quickly). The RTOs' hourly markets also generally support the provision of ancillary services that are a function of hourly load and generation, such as reserves (having some quantity of generating capability above actual electrical demand in the market and available to operate in order to be able to "fill in" in the event of a sudden and unexpected loss of generation or other system assets); and "regulation" or "load-following" service (having resources on the system with room to quickly increase and decrease output in order to manage second-to-second and minute-to-minute variations in net load on the system). Since the requirements for these services is also hourly and tied to generation capability, payments and pricing for such services is generally managed in combination with energy market unit commitment and dispatch methods.

In the wholesale market regions, owners of non-utility-owned generating assets must recover their costs of investment and operation through markets,[38] rather than through regulated rates. Over the operating life of the asset, a resource owner seeks to recover total revenues – across all central market and bilateral market activity – in amounts that cover their operating costs, their investment, and an acceptable return on that investment.

Operations and Incentives in Energy and Ancillary Service Markets

At a minimum, energy/ancillary service markets allow power plant owners to recover their costs of producing energy in those hours. This is because the minimum offer price by a generation owner will include at least all of the variable costs of operation, including, for example, fuel costs, variable operations and maintenance (O&M) costs, and emission costs (e.g., the variable cost to operate emission control systems, or the cost to purchase allowances to emit the quantity of pollutant emitted in that hour). This amount will be *all* the asset owner recovers *only if* it is the marginal unit dispatched in that hour (meaning the clearing price paid to all units is exactly equal to this marginal unit's offer), and the offer price exactly equals these variable expenses. In this circumstance, then, the unit would be able to cover its operating expenses, but it would earn no additional revenue to offset fixed/annual costs or provide a return of or on investment.

In reality, most generating units that end up being dispatched typically earn some margin above their variable operating expenses. This may be due in part to the ability of an asset owner to build into its offer some amount of cushion above expenses. Moreover, over the course of a year the unit will earn revenues from the energy market in excess of variable costs because in many hours the unit will not be the marginal unit, but rather will be "inframarginal," and that the clearing price it earns (set by a higher-priced unit on the margin) will exceed its costs. In some hours this difference can be large.

Although RTOs seek to dispatch plants in economic-merit order (starting with the lowest cost and then committing plants up to the amount needed to serve load and

[38] "Markets" reflects a combination of (a) centralized markets for the physical supply of energy, ancillary services, and (in some RTOs) capacity, and (b) bilateral financial transactions (e.g., hedging contracts; joint ownership agreements) in which the seller and buyer make commitments that lock in price certainty and other obligations surrounding electricity supply.

provide ancillary services) and in so doing minimize the total costs to provide power over time, there are features of the electric system that constrain this goal in practice. These constraints include, among other things, the operating characteristics of power plants or the existence of congestion on transmission pathways that prevent an economical unit from being operated.

RTOs dispatch the system fully aware of unit-specific information about the operating characteristics of the power plants on the system, regardless of who owns them. Each generating unit provides information about such things as: the time it takes to start up the unit and then ramp it up to full load; operational limits between maintenance outages; the minimum load at which it can operate; the number of starts and stops it may have in a year; and so forth. Some generating units have limitations in their air-emissions permits that set out their maximum run-time on certain fuels. The RTO takes all of these specifications into account in determining the dispatch of the system. These restrictions also limit a generating unit's ability to operate and capture revenues in wholesale markets, and can lead to the dispatch of a higher-priced unit on the margin.

Incentives in Capacity Markets and Resource Adequacy Obligations

Typically, if a developer of a new power plant or the owner of an existing one expects that net energy and ancillary service market revenues will equal or exceed what the developer/owner needs to cover going-forward capital investment plus a return on that investment, that developer/owner will proceed with the investment absent any additional sources of revenue. However, in most RTO regions, energy market prices are not typically high enough or often enough to produce sufficient net revenues to support major capital investment – whether in new or repowered generating capacity, or in major incremental investments in existing assets.

Consequently, many RTOs either administer central markets for the purchase of capacity or set a "resource adequacy" requirement on load-serving entities which provide incentives for them to construct or enter into bilateral arrangements to purchase capacity from generators (and/or demand-side resources). In some cases the RTO administers some form of hybrid approach that has elements of both a capacity market and a resource adequacy/self-supply requirement. These frameworks are designed (in combination with net energy/ancillary service market revenues) to provide incentives for the construction of new capacity resources when needed (as a result of load growth or retirement of existing assets), and/or to provide sufficient revenues for investment in unit upgrades, repairs, or other capital-intensive requirements (such as add-on emission control systems). Specifically, these mechanisms provide for an additional potential stream of revenues to generators.

Importantly, the mechanism and timing of capacity market revenues is significantly different from energy, with implications for how resource owners think about how they will manage environmental compliance options and whether they will make investments and/or operational changes to deal with environmental obligations. Energy prices are set and change on an hourly basis, and are priced and collected on the basis of dollars per megawatt-hour of energy generated. Capacity payments are typically fixed monthly payments based on prices determined in monthly or annual auctions.[39]

The incentive for investment in new capacity and for investment in major capital additions on an existing unit – e.g., for the installation of emission control technology – is driven in part by a developer/owner's expectations of *net* revenues to be earned in the various wholesale markets. If expected net revenues equal or exceed what is needed to make the investment with a sufficient return on that investment, no additional revenue streams – such as from a capacity market – are needed to decide to go forward with the investment.

[39] For example, in New England and PJM, capacity auctions occur three years prior to the year of need, and result in a price per unit of capacity (e.g., dollars per kilowatt-month) that is paid out to suppliers on a monthly basis.