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FEDERAL ENERGY REGULATORY COMMISSION

Technical Conference on Environmental Regulations and  
Electric Reliability, Wholesale Electricity Markets, and  
Energy Infrastructure

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**Central Region – March 31, 2015**

**I. Introduction**

My name is Amy Farrell and I am Vice President of Market Development for America's Natural Gas Alliance ("ANGA"). I appreciate the opportunity to participate in the Central Region Technical Conference to discuss implications of compliance approaches to the U.S. Environmental Protection Agency's ("EPA") Clean Power Plan ("CPP") proposed rule. I offer these comments and those to be provided at the conference in the context of EPA's proposal, assuming EPA's interpretation of its authority and the ensuing proposed regulatory structure. My comments should not be interpreted as a formal position on the relative merit of the proposal or its components, as ANGA neither supports nor opposes the CPP.

ANGA represents North America's leading independent natural gas exploration and production companies. We work with industry, government and customer stakeholders to increase demand for, and ensure availability of, our nation's natural gas resources for a cleaner and more secure energy future. The collective natural gas production of ANGA member companies is approximately eight trillion cubic feet annually, which represents approximately one third of total U.S. production. As both energy producers and consumers, ANGA has a keen interest in the production of electricity from clean-burning, affordable natural gas.

**II. Natural Gas Supply Abundance**

The United States' natural gas supply is affordable and abundant and is able to support significant demand growth across all sectors of the economy including power generation, manufacturing, transportation and exports. The shale gas revolution has transformed our nation's energy landscape. Technological developments, such as horizontal drilling and advancements in hydraulic fracturing, have led to more productive and efficient wells. As a result, domestic supplies will meet current and future states' demand for natural gas. To put our resources in context, the volume of natural gas consumed in 2014 in the U.S. was 27 trillion cubic feet.<sup>1</sup> The

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<sup>1</sup> U.S. Energy Information Administration, "Natural Gas Consumption by End Use," February 2015.

most recent projections show a range of technically recoverable dry gas from 2,200 to 3,500 trillion cubic feet using today's technology with 1,500 trillion cubic feet available at less than \$5/mmbtu.<sup>2</sup>

In addition to this long-term, abundant and affordable supply picture, short- to medium-term supply dynamics are equally attractive. Since 2005, U.S. dry natural gas production has increased 42 percent, natural gas consumption has increased 22 percent and natural gas spot prices have declined 50 percent.<sup>3</sup> The robustness and resiliency of U.S. natural gas production was further borne out by the rapid replenishment of natural gas storage levels this past injection season. The 2013-2014 winter was severe and stressed both the electric grid and the natural gas delivery systems; however, no bulk power outages occurred and natural gas customers utilizing firm contracts did not experience supply curtailments.<sup>4</sup> The rare, 1-in-30 winter caused natural gas storage volumes to be depleted to levels not seen since 2003. However, due to significant production increases from natural gas producers, storage injections set weekly records throughout the injection season. In fact, the April 1 to October 31, 2014 total injection volume set a new season record at 2,734 Bcf.<sup>5</sup> This exemplifies the quickness with which producers are able to respond to market needs.

### **III. Environmental, Economic and Grid Benefits of Increased Natural Gas Use**

Natural gas is a low-cost technology that can, and does, provide reliable baseload, peaking or intermediate power. Given its ability to ramp up quickly, natural gas-fired power plants play an important role in maintaining electric system reliability and accommodating intermittent electricity sources, such as wind and solar generation. Natural gas also assists in reducing air pollution emissions associated with electricity generation. Current U.S. Energy Information Administration ("EIA") data indicate that annual carbon dioxide ("CO<sub>2</sub>") emissions from the electric power sector in 2013 were 364 million metric tons less than annual emissions in 2005.<sup>6</sup>

Natural gas power plants are highly efficient and emit no mercury air pollution, virtually no sulfur dioxide or particulate matter, and significantly lower nitrogen oxides and greenhouse gases when compared to other types of fossil fuel power plants.<sup>7</sup> In addition, natural gas power

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<sup>2</sup> ICF International, "U.S. LNG Exports: Impacts on Energy Markets and the Economy," May 2013, 45.

<sup>3</sup> EIA, "Short Term Energy Outlook." March 2015, accessed March 24, 2015, <http://www.eia.gov/forecasts/steo/query/index.cfm?periodType=ANNUAL&startYear=2005&endYear=2016&formulas=x73xmx4x3px4x8>.

<sup>4</sup> Federal Energy Regulatory Commission, "Winter 2013-2014 Operations and Market Performance in RTOs and ISOs," April 2014, accessed March 23, 2015, <http://www.ferc.gov/CalendarFiles/20140402102127-4-1-14-staffpresentationv2.pdf>.

<sup>5</sup> EIA, "After record injections, natural gas storage levels now within 7% of 5-year Average," November 7, 2014, accessed March 23, 2015, <http://www.eia.gov/todayinenergy/detail.cfm?id=18731>.

<sup>6</sup> EIA, "Monthly Energy Review," September 2014, Table 12.6, accessed March 23, 2015, [http://www.eia.gov/totalenergy/data/monthly/pdf/sec12\\_9.pdf](http://www.eia.gov/totalenergy/data/monthly/pdf/sec12_9.pdf).

<sup>7</sup> National Energy Technology Laboratory, "Life Cycle Analysis: Power Studies Compilation Report," January 2011, Chapter 4.

plants have a small physical footprint when compared to other similarly sized power plants, including renewables, making natural gas a clear choice for urban, suburban, and other space-constrained areas. Because of the low emissions and small footprint of natural gas power plants, they can also be sited closer to urban areas and other demand centers for power, relieving electric grid transmission constraints and the need for long distance high-voltage power lines.

#### **IV. Both The Natural Gas and Electric Sectors Were In Transition Before The Clean Power Plan Announcement**

Since 2007 the natural gas industry has been in significant transition mainly due to changes in supply and demand market fundamentals. With the commercial viability of hydraulic fracturing and horizontal drilling, natural gas reserves once thought to be economically infeasible have become the mainstay of domestic natural gas production. This access to abundant and affordable natural gas supplies has had ripple effects throughout the economy from increased use in electric generation to on-shoring of manufacturing to U.S. exports of natural gas. As new shale gas production basins have been developed, so too has the needed infrastructure to connect these production basins with demand centers. This trend will continue assuming policies at both the state and federal levels remain fair and predictable and continue to enable such development. Over 131 Bcf/d of cumulative infrastructure additions have been developed since 2007, which is almost double the cumulative capacity added between 2000 and 2006. Looking ahead, over 55 Bcf/d of additional capacity has been proposed to come online by 2018.<sup>8</sup>

The electric sector has also been in transition for many years due to a variety of factors, including electric market restructuring, state renewable and alternative energy plans, regional carbon initiatives, EPA regulatory actions, an aging generation fleet and the abundance and affordability of domestic natural gas. As a variety of these factors have coalesced in specific regions throughout the country and natural gas fired generation has increased, market regulators have paid increasing attention to natural gas and electric sector interdependencies. This includes reviews of how the gas and electric markets interact to deliver electricity on any given day as well as how electricity markets interact with natural gas markets over time to drive (or not drive) necessary natural gas infrastructure investment.

##### **A. Natural Gas – Electric Interdependency and Infrastructure Adequacy**

The Federal Energy Regulatory Commission (“Commission”) has been evaluating the coordination of natural gas and electric markets since February 2012. Over the course of the past several years, the Commission has hosted technical conferences, released quarterly status reports and proposed a rulemaking to better schedule natural gas and electricity markets.

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<sup>8</sup> EIA, “Pipeline Projects,” October 1, 2014, accessed November 30, 2014, <http://www.eia.gov/naturalgas/data.cfm#pipelines>.

In addition to these actions, many national and regional studies have been completed that examine the issue of natural gas and electric interdependencies and infrastructure adequacy. The findings below pertain to the Central region:

The Electric Reliability Council of Texas (“ERCOT”) commissioned a study in 2012 to examine the risk of gas supply curtailment to electric generators within its service territory. The study found that ERCOT’s electric generators’ gas supply capacity “is well in excess of their peak natural gas needs.”<sup>9</sup>

The Midcontinent Independent Transmission System Operator (“MISO”) commissioned a study to examine the availability of pipeline capacity to serve natural gas-fired generation in its footprint. The study found that, “[o]verall, pipeline capacity in the MISO Midwest is positive and continually improving due to shale gas developments and accommodating pipeline expansions, contract expirations and the benefits of increased pipeline reticulation underway in the Eastern Interconnect.”<sup>10</sup>

The Eastern Interconnect Planning Collaborative (EIPC) published its Draft Target 3 results in February 2015. The report found that “[i]n MISO North/Central, the ‘rest of RTO’ area of PJM, TVA and IESO, the consolidated network of pipeline and storage infrastructure is highly resilient in response to the postulated gas-side contingencies on the Winter Peak Day in 2018, thus resulting in negligible affected generation”.<sup>11</sup>

The majority of the infrastructure studies referenced in this section target natural gas availability for gas-fired electric generators on natural gas peak demand days. These studies do not directly assess annual natural gas availability for gas-fired electric generators. Given the often significant availability of delivered natural gas for electric power generation on peak gas demand days, one can infer an even greater amount of gas infrastructure available for electric power generation throughout the year. Recognizing that pipeline design capacity is largely driven by demand to serve heating load and other firm customers in peak winter months, the availability of significant capacity throughout the year is particularly prevalent in areas where winters are cold and there is a large difference between peak and non-peak demand months capacity utilization rates.

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<sup>9</sup> Black & Veatch, “Gas Curtailment Risk Study,” March 2012, 27.

<sup>10</sup> EnVision Energy Solutions, “Phase III: Natural Gas-Fired Electric Power Generation Infrastructure Analysis: An Analysis of Pipeline Capacity Availability,” December 2013, Appendix, 8.

<sup>11</sup> Levitan & Associates, Inc, “Draft Gas-Electric System Interface Study, Target 3 Report, Natural Gas and Electric System Contingency Analysis,” February 27, 2015, iii.

## B. Fuel Assurance Provisions at ISO/RTOs

Across the U.S., electric power generators contract differently for delivered natural gas supplies. Depending on the market structure of the region, natural gas-fired generators may rely more heavily on firm contracts or interruptible contracts. In a report to the Eastern Interconnection Planning Collaborative (“EIPC”), Levitan and Associates describe the differences between firm and interruptible gas service and the reason for today’s physical gas pipeline system design as follows:

Interstate pipeline and storage companies offer two basic services: firm transportation and/or storage, and interruptible transportation and/or storage. Pipeline and storage infrastructure capacity is sized strictly to meet the demand of firm customers, that is, those entitlement holders who pay the FERC-authorized cost of service rate to ensure guaranteed deliverability under all circumstances, except force majeure. Historically, force majeure events are rare, and include only the most severe or unusual operating conditions when mainline segments or compression stations are not available, thereby reducing a pipeline’s physical delivery capability.<sup>12</sup>

Regulatory stability and a market that consistently prices capacity at the appropriate level (for regions where capacity markets exist) are needed to promote rational long-term investment decisions, including firm delivery commitments. Two RTOs recently have taken steps to provide an improved market platform to facilitate such commitments. ISO New England has introduced its pay-for-performance program which provides financial incentives for generators to ensure reliable fuel supplies. And PJM has filed a proposal with the Commission to establish a new Capacity Performance resource designation together with similar financial incentives to incentivize reliable fuel supply programs.

## V. The Proposed Clean Power Plan Creates A Unique Challenge

The proposed Clean Power Plan has drawn more attention to the natural gas and electric interdependency conversation, and in particular questions about infrastructure adequacy. This is largely driven by EPA’s building block two, which concludes that existing natural gas fired generation can run at a 70 percent capacity factor. As stated in our introduction and in our filed comments to EPA, we do not support or oppose EPA’s proposed rule or opine on the appropriate level to set the standard, however we do provide comment on the capabilities of natural gas fired generation and the associated infrastructure. ANGA does believe that existing natural gas infrastructure is able to support 70 percent annual capacity factors at existing natural gas combined cycle (“NGCC”) facilities.

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<sup>12</sup> Levitan & Associates, Inc., “Gas-Electric Interface Study: Existing Natural Gas-Electric System Interfaces,” February 2014, 11.

Firstly, natural gas combined cycle facilities have demonstrated their ability to run at capacity factors at or above 70 percent. Based on ANGA’s review of EPA’s Continuous Emissions Monitoring (CEMS) hourly operating data, 40 percent of currently operating NGCCs in the U.S. (211 units) have achieved at least one year since 2000 where their annual capacity factor was greater than 70 percent. Additionally, we found that 83 percent (444 units) of currently operating NGCCs in the U.S. have achieved at least one month since 2000 where their monthly capacity factor was greater than 70 percent. This data supports EPA’s conclusion that NGCC units are able to achieve or exceed a 70 percent capacity factor.

Secondly, existing infrastructure currently supports increased utilization of natural gas in electric generation. This was demonstrated in 2012 when natural gas prices reached the lowest level in over a decade and NGCC generation increased significantly due solely to economics. The reason continued increased use of existing NGCCs is possible is due to the current natural gas pipeline capacity and the utilization of such capacity. Much of each state’s natural gas infrastructure has been built to meet reliability requirements for residential, commercial and other firm customers peak load put forward by the state’s public utility commission. During the non-peak natural gas demand months (March-November), higher pipeline capacity, or “headroom”, exists for additional gas to move through the system. Existing electric generators can utilize this additional capacity to serve electric load.

While ANGA agrees with the technical ability of existing NGCCs to run at a 70 percent annual capacity factor, we also recognize that the winter natural gas peak day can still pose a reliability issue with the current infrastructure in place. Without additional natural gas infrastructure (additional pipelines and/or storage) in constrained regions, alternative generation sources need to exist to solve for the natural gas peak day constraint. Whether or not this alternative capacity is called to generate, this capacity needs to be compensated appropriately to justify its readiness to operate.

## **VI. New Generation Will Require New Pipeline Capacity**

Assuming that the state standards move forward as proposed and given that the stringency of the proposed standards are not solely based on fossil fuel-fired generation, state compliance with these standards will likely lead to new natural gas generation capacity to fill any generation gaps from retiring units and to support increased renewable capacity. This new generation will require new natural gas infrastructure especially in areas that are just now starting to build more natural gas-fired generation.

Fortunately, significant infrastructure investment is already underway. The Central region in particular will benefit from ongoing and planned pipeline expansions from producing regions to demand markets. Westbound infrastructure originating in the Northeast producing region totals over 11 Bcf/d. Additionally, over 9 Bcf/d of infrastructure additions originating from the

Northeast producing region serve south central demand. While some of these projects are new pipelines, other projects are transitioning unidirectional capacity to bidirectional capacity. This bidirectional capacity provides further resilience to the underlying natural gas infrastructure in both regions

## **VII. Implementation Matters**

Just as the form of the standard (average annual rate) matters in determining the most cost-effective way to comply (increased existing natural gas utilization), the form of the compliance metric (rate vs. mass) determines the increased costs that will be seen by electric customers and whether states will be able to serve future growing electric load.

In a mass based system a facility must pay (or submit an allowance) for every ton of CO<sub>2</sub> generated, so the price those units bid into the market will reflect the cost for every ton of CO<sub>2</sub> generated. Under a rate based system, a facility emitting more tons of CO<sub>2</sub> per MWh than the level of the standard only pays for the emissions above the level of the standard, versus every ton emitted. This results in a lower net CO<sub>2</sub> compliance cost, which leads to lower electricity prices for consumers (see figure 1 attached).

Additionally, a rate based standard measures the overall emissions rate of the existing fleet. By measuring compliance as emissions per unit generated, states do not limit the total generation. This leaves the possibility of increasing NGCC generation to meet growing electric load. This, along with leaving emissions from new generation outside of the standard, is particularly important in states that plan to partake in the manufacturing renaissance being ushered in by affordable, stable natural gas prices.

## **VIII. Answers To Specific Questions Posed**

*1. Given the diversity of entities in the Central region, how can potential infrastructure needs be identified, planned for and constructed in time to comply with the proposed Clean Power Plan? How will Order No. 1000 and other regional and interregional planning processes identify and plan for infrastructure needed to comply with the Clean Power Plan? Are additional mechanisms or processes needed?*

Much of the Central region appears well-positioned to secure additional natural gas capacity, particularly when compared to other regions., This is because firm natural gas contracts can be executed at the load serving entity level as opposed to the capacity procurement process that exists in other regions.

*2. How will compliance with the proposed Clean Power Plan affect existing transactions between RTOs/ISOs and between states in the Central region? Will changes to trading patterns cause the need for new infrastructure (e.g., electric transmission, natural gas pipelines, gas*

*storage facilities)? If so, how will construction of the needed infrastructure be synchronized with compliance to the rule?*

The effect on existing transactions between RTOs/ISOs and between states will highly depend on the states' chosen compliance plans. If states choose to retire existing fossil facilities and construct new natural gas combined cycles, the need for new natural gas infrastructure is likely. If the states' comply by ramping up existing NGCCs, they could use the existing infrastructure in non-peak natural gas demand periods and rely on other generation capacity during natural gas peak demand periods to provide the necessary generation. If the states' rely more on renewables, additional natural gas generation capacity and natural gas infrastructure will be needed to solidify generation. Additionally, potential associated electric transmission infrastructure will be needed with substantial renewable builds. The main driver of changes in trading patterns will likely be the different level of standards between states as defined in the Clean Power Plan proposal.

*3. Will current approaches to resource adequacy support investment in additional generating resources needed for compliance with the proposed Clean Power Plan? Are changes to existing approaches or the creation of new approaches necessary to facilitate investments needed for compliance?*

This is an issue between existing facilities and new facilities. Before the Clean Power Plan was proposed, the electric sector was transitioning to more natural gas and renewable capacity; however, depending on the states' compliance plan approaches, this transition may occur more quickly than otherwise assumed.

*4. Given the possibility that a large amount of coal-fired generation in the Central region could be retired as a result of both the Mercury and Air Toxics Standards and the Clean Power Plan, what issues may arise if many of these units are required to stay online as Reliability Must Run units or System Support Resources? If transmission upgrades must be built to allow Reliability Must Run units or System Support Resources to retire, how will that affect the timing of compliance with the Clean Power Plan?*

If coal facilities are required to stay online for reliability must run requirements, then the Clean Power Plan should allow for such actions until the necessary transmission upgrades are completed.

*5. Please discuss the various electric and gas transmission issues that may arise as a result of potential increases in new renewable and gas-fired generation.*

It is imperative that the necessary electric generation capacity is available to generate electricity to serve demand at all times. Where new renewables are added, natural gas fired generation



must be available (either new capacity or increased generation from existing sources) in order to support the resource and firm up the grid. For sense of scale, according to assumptions in ICF's *Firming Renewable Electric Power Generators: Opportunities and Challenges for Natural Gas Pipelines* (March, 2011) report, 259 MW of reserve gas capacity is required for every 1,000 MW of wind/solar integrated into the grid.

Supporting this "firming" capacity may require increased fixed-cost payments to generators who do not generate electricity often, but do provide the necessary capacity for reliability requirements. Given the Clean Power Plan's breadth and depth, this may result in current capacity operating at high capacity factors to transition to capacity operating at low capacity factors. These facilities should receive appropriate compensation to incent continued generation availability.

*6. Please comment on any studies that have been performed with respect to infrastructure needs in the Central region to comply with the Clean Power Plan.*

The following studies analyze the impact of the Clean Power Plan and include the whole and/or parts of the Central region; however, not all of these studies explicitly describe the infrastructure needs associated with the Clean Power Plan's implementation:

- a) MISO's Analysis of EPA's Proposal to Reduce CO<sub>2</sub> Emissions from Existing Electric Generating Units, released November 2014.
- b) ERCOT's Analysis of the Impacts of the Clean Power Plan, released November, 2014.
- c) SPP's Reliability Impact Assessment of the EPA's Proposed Clean Power Plan, October 2014.
- d) NERC's Potential Reliability Impacts of EPA's Proposed Clean Power Plan, November 2014.
- e) Center for Strategic and International Studies' Remaking American Power, November 2014.
- f) U.S. Department of Energy's Natural Gas Infrastructure Implications of Increased Demand from the Electric Power Sector, February 2015.

While each of these studies examine the Clean Power Plan, the modeling structure chosen, assumptions used and results reported differ significantly across each study. ANGA strongly encourages each state and RTO/ISO in the Central region to examine the impacts of rate-based implementation versus mass-based implementation. Given the Central region's unique position to capitalize on the manufacturing renaissance occurring in the U.S. as a result of low cost natural gas, it is likely that the adoption of rate-based standards will lead to the greatest flexibility to respond to growing economies, increased electric load and changing market demands.

*7. Are adaptations to current Commission policies needed to facilitate the development of necessary infrastructure for the Central region?*

The best policy assurance to meeting reliability targets is the following:

- a) Ensure that appropriate cost recovery mechanisms are in place for existing facilities to provide generation when called upon, even if such generation is needed in limited time periods throughout the year.
- b) Ensure that electric generators are able to “anchor” a new pipeline in both restructured and vertically integrated markets.

## **IX. Conclusion**

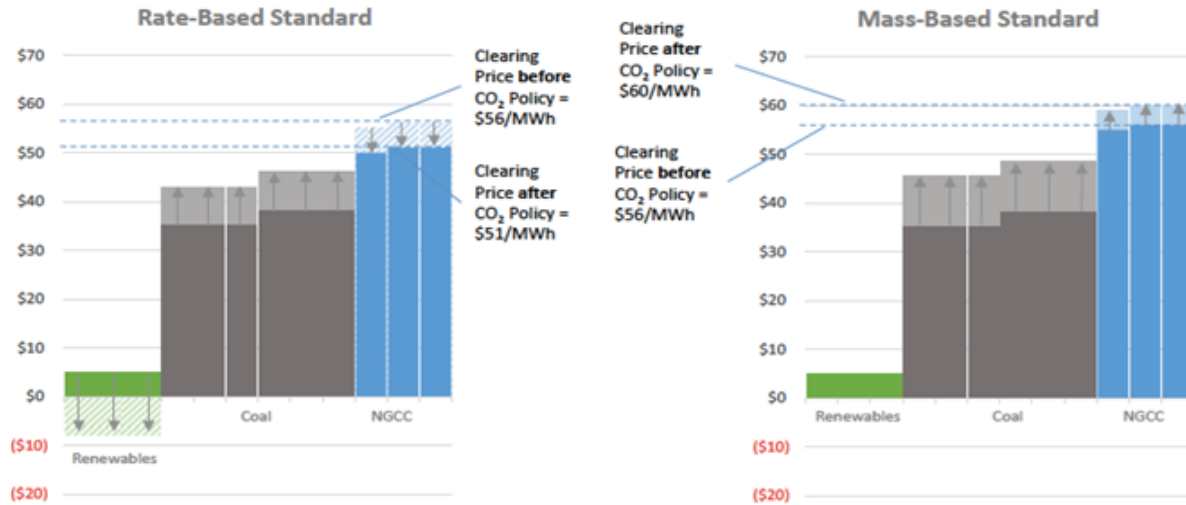
Innovation in natural gas production in the United States has become a transformative force. We have an abundant and affordable supply of natural gas able to support significant demand growth across multiple sectors including power generation, manufacturing, transportation and exports. The proposed Clean Power Plan will create significant cost increases for consumers; however, states have the ability to lessen this cost impact based on how they choose to execute their compliance plans, i.e. implementation matters. Increased generation by existing natural gas combined cycles provides the most cost-effective compliance solution for states to use under any CPP scenario. As states increase utilization of existing NGCC plants and build new natural gas plants to support new growth and to firm intermittent resources, new natural gas infrastructure will be needed. These needs, however, can be met assuming appropriate federal and state policies remain in place to enable such infrastructure builds. The form of the standard will also determine costs. A rate based compliance approach will result in lower consumer electricity costs and will allow for future load and economic growth within the state.

Respectfully submitted,



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**Figure 1: Rate-Based Standard Versus Mass-Based Standard Example**



In the rate-based example, assuming a state goal of 1,300 lbs/MWh and a CO<sub>2</sub> price of \$20 per ton: (1) renewable energy sources would earn a CO<sub>2</sub> credit of \$13/MWh; (2) coal plants would incur a cost of \$8/MWh; and (3) NGCC plants would earn a CO<sub>2</sub> credit of \$5/MWh. Although, NGCC plants earn a CO<sub>2</sub> credit of \$5/MWh, wholesale electric prices would decline by an equivalent amount (i.e., net revenues remain unchanged).

In the mass-based example shown, assuming a CO<sub>2</sub> price of \$10 per ton: (1) renewable energy sources would not be charged; (2) coal plants would incur a cost of \$11/MWh; and (3) NGCC plants would incur a cost of \$4/MWh. With NGCC units on the margin, wholesale electric prices would increase to reflect the carbon price.