AEE INSTITUTE

IMPACTS OF THE CLEAN POWER PLAN ON U.S. NATURAL GAS MARKETS AND PIPELINE INFRASTRUCTURE

June 2015

ABOUT AEE INSTITUTE

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EXECUTIVE SUMMARY

The Environmental Protection Agency's proposed Clean Power Plan (CPP) establishes state-by-state carbon emissions rate targets that it projects will reduce U.S. electricity sector carbon emissions 30% below 2005 levels by 2030. Some stakeholders, including the North American Electric Reliability Corp. (NERC), have raised concerns that states might rely heavily on natural gas generation for CPP compliance, creating stress on gas pipeline capacity and ultimately affecting electric system reliability. While it is likely that states will pursue a diverse portfolio of emission reductions, examining the infrastructure implications of gas use scenarios helps with risk management.

The AEE Institute contracted with ICF International to perform an assessment of the potential impacts of the CPP on required gas pipeline capacity. AEE Institute specified three scenarios in the U.S. electricity and natural gas markets for ICF to analyze. The Reference Case is a business-as-usual future without the CPP.[1] The basic CPP Case assumes each state will reach its rate-based emissions target as proposed in the CPP by 2030 with resources competing in the model to provide the necessary emission reductions.[2] The Low Gas Price CPP Case considers the same emissions targets and approach as in the CPP Case, but assumes natural gas prices are approximately 20% lower than expected, leading to increased gas consumption.

No Significant Increase in Pipeline Needs under CPP, Even With Low Gas Prices

Figure 1 (next page) shows the modeling results for the net incremental gas demand contribution of the CPP and Low Gas Price CPP Cases compared to the Reference Case.[3] Under the Reference Case, natural gas demand continues to grow through 2030. Under the CPP Case, there is a temporary increase in natural gas demand above the Reference Case due to the incremental shift from coal to gas. Incremental demand then declines over time as additional renewable energy and demand-side resources come online. Since this incremental demand is small, even if coal to gas switching becomes a more prominent compliance mechanism, as under the low future gas prices scenario, this modeling shows that it would not cause a significant increase in new pipeline requirements. There is, however, regional variation among these results: Changes in gas consumption and infrastructure are concentrated in the Northeast, but could be greater in the South and Midwest if gas prices are lower.

Consistent with some prior studies from EPA[4] and DOE,[5] this report finds that ongoing changes in the U.S. natural gas market independent of the CPP are driving increases in pipeline gas infrastructure, prompted by dramatic growth in new gas supplies from areas like the Marcellus and Utica shales. This report further finds that compliance with the CPP, even under an unlikely "stress test" scenario of unexpectedly high gas usage, would only modestly increase the gas infrastructure needs, in the range of 3% to 7%.

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[1] This Reference Case is based on EPA assumptions and is different from ICF's commercial reference case.

[2] The exception is energy efficiency, which is handled in the model as an exogenous variable, so AEE Institute used the levels of energy efficiency assumed by EPA in its Regulatory Impact Analysis (RIA).

[3] This report focuses on pipeline capacity needs over an annual or multi-year period. The analysis does not consider the impact of daily variability on gas load, which is another important driver of pipeline infrastructure development.

[4] U.S. Environmental Protection Agency. "Regulatory Impact Analysis for the Proposed Carbon Pollution Guidelines for Existing Power Plants and Emission Standards for Modified and Reconstructed Power Plants," June 2014, EPA-452/R-14-002.

[5] "Natural Gas Infrastructure Implications of Increased Demand from the Electric Power Sector," Department of Energy, February 2015.

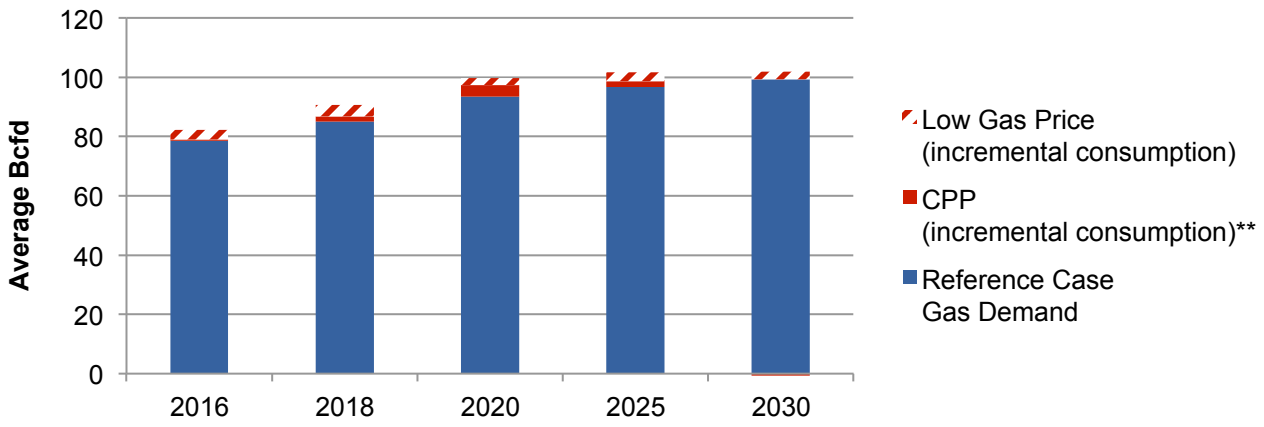
Three key factors explain this outcome:

- A large number of pipeline projects are already in the planning stages to expand capacity over the next three to five years. These planned projects are sufficient to meet both the anticipated growth in gas demand in the Reference Case (that is, demand growth not related to the CPP) as well as much of the incremental demand in the CPP cases.

- The assumed increase in energy efficiency in the CPP cases reduces electric load growth relative to the Reference Case. Because electric load growth is lower, power sector gas demand in the Northeast and West regions is actually lower in the CPP Case in 2030 than in the Reference Case, and only slightly higher than the Reference Case in the CPP Low Gas Price Case.

- Third, while Midwest and South power sector gas consumption is projected to increase in both CPP cases, these areas are relatively close to incremental gas supplies (principally the Marcellus and Utica shales). The proximity of the incremental gas demand to the source of the incremental supplies and the reversals of existing pipelines (moving gas from Marcellus/Utica to the Midwest and South on existing pipelines) reduces the amount of new pipeline and capital expenditures required.

Figure 1. Projected U.S. Natural Gas Demand in AEE Institute Scenarios *



* Includes residential, commercial, industrial, electricity generation gas consumption, pipeline fuel, lease and plant gas use, exports to Mexico, and LNG exports.

** By 2030, gas demand in the CPP Case is about 0.7 Bcfd lower than the Reference Case.

The pace of investment in new pipeline capacity over the past decade suggests that these projected future investments, with or without the CPP, are well within the capabilities of the industry. This conclusion is reinforced by the fact that there are numerous competitive options for emission reduction available in the marketplace that collectively reduce the risk of heavy dependence on natural gas for compliance.[6] Furthermore, this analysis does not capture the evolution of certain technologies (e.g., gas demand response) and electricity grid operational techniques (e.g., ISO New England's Pay for Performance rules), which are changing and will continue to change the relationship between gas demand and infrastructure needs.

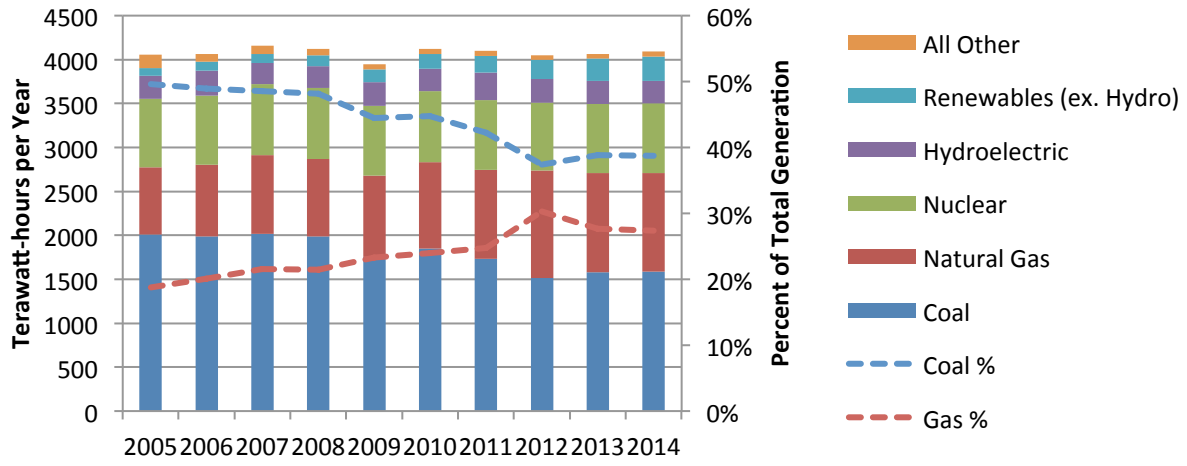
[6] Competitiveness of Renewable Energy and Energy Efficiency in U.S. Markets, AEE Institute, June 2015. Available at: http://info.aee.net/competitiveness-of-renewable-energy-and-energy-efficiency-in-us.

INTRODUCTION

The Environmental Protection Agency's proposed Clean Power Plan (CPP) establishes state-by-state carbon emissions rate targets that it projects will reduce U.S. electricity sector carbon emissions 30% below 2005 levels by 2030. To develop the state-specific standards for the proposed CPP, EPA developed a best system of emission reduction (BSER) framework to assess the potential emission reductions available in each state. EPA included four components, called "building blocks" in its BSER framework: 1) improving the efficiency of existing coal plants, 2) increasing the utilization of existing gas-fired generators with a corresponding decrease in the use of existing coal-fired generation ("coal to gas switching"), 3) increasing the use of zero-emissions resources, including renewable energy technologies and nuclear power, and 4) expanding end-use energy efficiency programs. The CPP requires states to develop plans to achieve the specified emission rate standards using any combination of the resources within the BSER along with other emission reduction resources not listed (e.g., demand response, transmission and distribution improvements, etc.).

Although there are numerous competitive options available for emission reduction, some stakeholders, including the North American Electric Reliability Corp. (NERC), have raised concerns that states might rely heavily on natural gas generation for compliance, creating stress on gas pipeline capacity and ultimately electric system reliability. The past decade has already seen a significant shift in U.S. electricity generation away from coal and toward natural gas. Even without CO_2 emission regulations, coal-fired plants have been retiring at an increasing rate due to relatively low natural gas prices, as well as in response to other emissions regulations, principally the Mercury and Air Toxics Standards (MATS) Rule. Over the past decade, coal's share of total U.S. generation has dropped by roughly 10%, while the natural gas share has increased by about the same amount (Figure 2).

Figure 2. U.S. Electricity Generation by Fuel, 2005-2014



Source: EIA

In order to analyze the gas pipeline capacity that could be necessary under the proposed CPP framework, the AEE Institute contracted with ICF International to complete an assessment of the potential impacts of the CPP. The analysis is designed to examine the total pipeline capacity expansions expected over the next 15 years (2016 through 2030) without the CPP, determine the incremental capacity requirements prompted by the CPP,

and examine how unexpectedly low future gas prices could affect requirements for gas delivery infrastructure by increasing gas demand. While the competition between cost effective emission reduction resources makes the last scenario unlikely, examining the infrastructure implications of an unexpectedly high gas use "stress test" scenario helps with risk management.

The analysis uses the same assumptions as EPA's Regulatory Impact Analysis (RIA) with respect to electric demand growth, the costs of new generating capacity, and the program structure of the CPP, among other market and policy drivers. The analysis determines the incremental need for new inter- and intra-state gas pipeline capacity to support the projected changes in inter-regional pipeline flows.[7]

The projections are derived from an examination of changes in annual and monthly gas consumption and inter-regional pipeline flow patterns. This level of granularity focuses on the availability of gas to meet CPP compliance needs over an annual or multi-year period. Natural gas pipeline companies need firm capacity commitments from shippers to build new capacity, so growth in annual average demand is a critical driver of pipeline additions. This analysis does not consider the impact of daily variability in gas load. The change in daily variability, and in particular the change in gas demand on peak winter days, is another important factor in assessing the ultimate need for additional pipeline infrastructure.

AEE Institute specified three scenarios in the U.S. electricity and natural gas markets for ICF to analyze. The three scenarios are summarized as follows:

- **Reference Case –** a business-as-usual future without the CPP;[8]
- **CPP Case –** a scenario assuming that each state reaches its rate-based emissions target as proposed in the CPP by 2030 with resources competing in the model to provide the necessary emission reductions;[9] and
- **Low Gas Price CPP Case** – a "stress test" scenario that considers the same emissions targets and approach as in the CPP Case, but assumes natural gas prices are approximately 20% lower than expected, leading to increased gas consumption.

Analytic Approach

In order to assess the potential impact of the CPP on gas demand and corresponding pipeline capacity, ICF used two of its proprietary models: the *Integrated Planning Model* or *IPM* (a version of the same power and emission market model used by EPA) and the *Gas Market Model* or *GMM* (which was used as the basis for EPA's gas market modeling approach).

IPM is a multi-regional, dynamic, deterministic linear programming model of the U.S. and Canadian power markets. IPM is used to forecast least cost capacity expansion, electricity dispatch, fuel consumption, and emission control strategies while meeting projected electricity demand and all assumed environmental, transmission, dispatch, and reliability constraints. EPA has used IPM for over two decades to better understand power sector behavior and evaluate the economic and emission impacts of prospective environmental policies, including the CPP.[10]

[7] This analysis does not include estimates for additional gathering or distribution system capacity.
[8] This Reference Case is based on EPA's RIA assumptions. As such, it differs from ICF's commercial reference case.
[9] The exception is energy efficiency, which is handled in the model as an exogenous variable, so AEE Institute used the levels of energy efficiency assumed by EPA in its RIA.
[10] Ibid.

GMM is a general equilibrium model of the North American gas market that solves for a complete natural gas balance (production, demand, pipeline flows, storage activity, and prices) at 121 market areas ("nodes") joined by over 400 pipeline corridors ("links"), which represent pipeline capacity connecting the areas. GMM forecasts monthly market activity. It includes ICF's recent assessments of non-power gas demand growth (including domestic consumption, LNG exports, and Mexican exports), supply costs, and announced plans for new pipeline capacity.

Using these models, ICF has projected the incremental changes in annual and seasonal natural gas consumption prompted by the CPP and the need for additional pipeline capacity to support those consumption changes. Specifically, ICF modeled three scenarios defined by AEE Institute:

- The **Reference Case** serves as a benchmark against which to measure the impacts of the other cases. The Reference Case includes ICF's estimates for the cost of developing incremental gas supplies, growth in non-power gas demand, and growth in U.S. gas exports. Assumptions related to power markets, such as electric demand growth, including the future impact of energy efficiency (EE), and the cost and performance of new generating capacity, are taken from EPA's Base Case v.5.13.[11] Existing regulations, including renewable portfolio standards and MATS, are also represented consistent with EPA's assumptions and its approach for Base Case v.5.13. The Reference Case does not include the CPP or any other federal CO_2 control program, but it does include representation of California's AB32 cap and trade program and the Regional Greenhouse Gas Initiative (RGGI).
- The **CPP Case** adds to the Reference Case a representation of the CPP CO_2 emission rate requirements for existing sources. For this case, AEE Institute had ICF implement the emission rate-based standards, expressed in pounds of CO_2 emitted per megawatt-hour of generation in IPM in a manner consistent with EPA's approach for its Option 1-State scenario in its Regulatory Impact Analysis for the CPP proposal.[12] That approach creates a glide path of standards over the interim compliance period (2020 to 2029) leading to the target standard in 2030, but allows states to bank and withdraw credits over the period. As such, the modeling reflects the fact that the interim target is an average emissions rate over the period thus allowing the states to choose their emission reduction trajectories. Credit trading is allowed within each state. The approach also allows for action in the lead up to the beginning of complicance in 2020.
- The **Low Gas Price CPP Case** is the same as the CPP Case except that it assumes lower incremental gas supply resource costs, resulting in commodity gas prices at Henry Hub about 20% lower than in the CPP Case. This price reduction is roughly equivalent to the average decline in gas prices between EIA's 2014 and 2015 Annual Energy Outlook (AEO) for the High Gas and Oil Resource cases over the years 2020 to 2040, reflecting the potential downside in the natural gas price forecast. The lower gas prices in the Low Gas Price CPP Case are intended to put upward pressure on gas consumption by the power sector to identify infrastructure needs under a "stress test" scenario with unexpectedly high use of gas for CPP compliance.

In each of the scenarios, the analysis incorporated concurrent changes to the natural gas market over the next 15 years, including:

- The continued growth of shale gas production, particularly in the Marcellus and Utica plays.
- The resurgence of U.S. industrial gas demand driven by low-cost shale gas supplies.
- The growth of U.S. gas exports to Mexico and LNG exports.

[11] EPA assumptions documented at http://www.epa.gov/airmarkets/programs/ipm/psmodel.html.

[12] U.S. Environmental Protection Agency. "Regulatory Impact Analysis for the Proposed Carbon Pollution Guidelines for Existing Power Plants and Emission Standards for Modified and Reconstructed Power Plants," June 2014, EPA-452/R-14-002.

- The changing balance of natural gas trade with Canada (reduced imports and increased exports of gas from the United States to Canada).
- Increases in gas consumption for electricity generation resulting from predictable factors (e.g., planned coal plant retirements driven by MATS compliance, electric load growth, etc.).
- Regional growth in residential and commercial gas consumption.

For the three scenarios, GMM was used to provide gas supply curves (gas prices as a function of consumption in the power sector) to IPM. IPM then solved for power sector gas consumption. IPM's projected power sector gas consumption was then fed back into GMM, which was run once more to project changes in the gas market and the resulting pipeline infrastructure requirements. As natural gas demand and production increase, additional pipeline capacity is required to support the changes in inter-regional gas flows.

Through 2020, each scenario's incremental pipeline capacity additions were based almost exclusively on projects that have already been proposed by pipeline companies. On links where more incremental capacity has been proposed than the projected need, only the amount needed to meet the peak monthly flow was added. After 2020, additional pipeline capacity was added when supported by the projected increase in flows, and where the projected difference in upstream and downstream gas prices (referred to as "basis differential") was sufficient to support the construction of new capacity.

The total pipeline additions were assessed based on their length (in miles) and capacity (in Bcfd). A pipeline's capacity is a function of the pipeline diameter (which is typically stated in inches) and the amount of compression on the system. Capital expenditures were based on the incremental inch-miles (pipeline diameter multiplied by mileage) added in each region.[13]

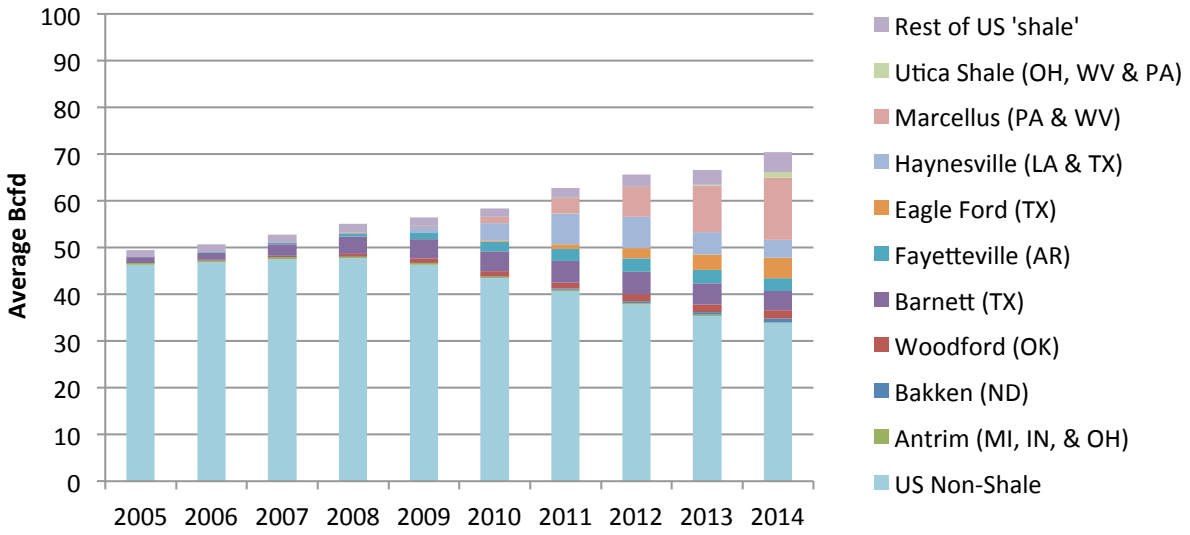
Recent Historical Changes in the Natural Gas Market

The shale gas revolution, which started at about the turn of the 21st century, has dramatically changed the landscape of the U.S. natural gas market. Emerging shale plays across the United States have offset production declines from conventional resources and created new supply centers. Incremental infrastructure has quickly been added to accommodate the growing production volumes, and existing pipelines originally built to transport gas from the Gulf coast and Rockies to the north and east are adapting their systems to provide new services. The relationships between regional gas prices (basis differentials) have also shifted to reflect the new supply/demand paradigm. Prior to the shale gas revolution, gas prices tended to be lower in the traditional gas producing areas along the U.S. Gulf coast, and higher in the Northeast. With rapid growth of Marcellus shale production in the Northeast, spot market prices in and around the Marcellus shale are often lower than Gulf coast gas prices.

Figure 3 shows that U.S. natural gas production increased from about 50 Bcfd in January 2005 to 70 Bcfd by December 2014. Production from shale resources has grown at 4% per year, on average, during the 10-year period and now exceeds production levels from non-shale resources. Notably, production from the Marcellus shale has risen to well over 15 Bcfd in as of 2014, and is currently one of the dominant supply sources in the United States.

[13] The cost per inch-mile of new pipeline capacity was based on data from the INGAA Foundation study, "North American Midstream Infrastructure through 2035: Capitalizing on Our Energy Abundance," prepared by ICF International, March 2014.

Figure 3. U.S. Natural Gas Production, 2005-2014



Source: EIA

Pipelines are integral links that transport gas from production areas to markets. Construction of existing pipeline infrastructure reflected the geographical locations of supply and demand growth. Figure 4 shows that between 2005 and 2008, production growth was concentrated in Rocky Mountain basins, and LNG imports were considered an essential future supply source to meet natural gas demand growth. Incremental pipeline infrastructure was primarily constructed in the Central and Southwest region (including Texas and Louisiana) to meet demand growth in the Southeast and Northeast. From 2009 through 2014, however, infrastructure growth shifted toward the Northeast due to new shale production growth in this area.

Figure 4. U.S. Pipeline Capacity Additions, 2005-2014

	2005 - 2008			2009 - 2014		
	Pipeline Miles	Capacity (Million cubic ft. per day)	Regional Capacity Percentage	Pipeline Miles	Capacity (Million cubic ft. per day)	Regional Capacity Percentage
Central	2,325	15,979	21%	2,078	12,219	17%
Gulf of Mexico	18	2,040	3%	-	-	-
Southwest	3,579	38,912	51%	3,427	32,045	44%
Northeast	835	7,860	10%	1,108	15,307	21%
Southeast	807	9,117	12%	1,271	12,387	17%
West	199	1,707	2%	330	1,150	2%
Total U.S. Lower 48	**7,763**	**75,615**	**100%**	**8,214**	**73,107**	**100%**

Source: EIA

Existing interstate pipelines have shifted their flow patterns responding to the supply realignment. For example, the Rockies Express pipeline, put in service at the end of 2009 to bring Rockies production to the Northeast market, only delivered 0.5 Bcfd of gas to Indiana in 2014, a 66% decline from the 2010 volume level. This reduction is a direct result of production from the Marcellus shale, which is displacing Northeast customers' needs for acquiring gas supplies from the Rockies. Three major pipelines serving the U.S. Northeast market – Transcontinental Pipeline, Tennessee Gas Pipeline and Texas Eastern Pipeline – also experienced similar flow

pattern shifts. Most of the supplies to the Northeast customers on these pipelines are now regionally sourced from Pennsylvania. Long-haul transportation volumes have largely stopped. For example, flows on Transco into Maryland through Station 190 averaged 0.94 Bcfd in 2014, as compared to 1.79 Bcfd in 2005, a decline of 47%.[14]

Electricity generators fueled by natural gas have gained market share as a result of relatively low gas prices and pressure on competing coal-fired sources from environmental regulations, such as MATS. While the actual gas used for power generation in any given year will fluctuate with electricity demand and spot natural gas prices, data from the past 10 years shows a clear trend toward increasing gas consumption (Figure 5).

Figure 5. Historical Power Sector Gas Consumption, 2005-2014

	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
Gas Consumption from the Power Sector (Bcfd)	16.1	17.0	18.7	18.3	18.8	20.2	20.8	25.0	22.3	22.3
Annual Growth Rate		6%	10%	-3%	3%	7%	3%	20%	-11%	0%

Source: EIA

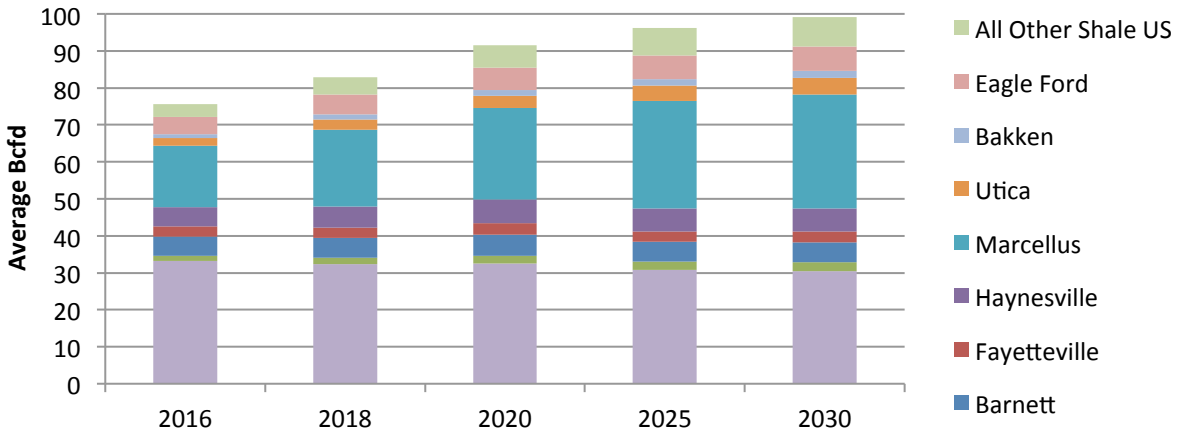
For regions with competitive electric market structures, where the marginal dispatch unit determines the wholesale price of electricity in the region, such as ISO-NE, the availability of natural gas pipeline capacity during the peak winter days becomes an increasingly important factor in determining the price of electricity. During the winter of 2013-14, cold weather increased both non-power and power sector gas demand, causing constraints on pipelines and dramatic spikes in spot gas prices, particularly in the Northeast and Mid-Atlantic.

RESULTS FROM THE REFERENCE CASE

The Reference Case analysis projects that production growth from shale resources will continue, leading total U.S. lower-48 production to exceed 90 Bcfd by 2020 and approach 100 Bcfd by 2030 as shown in Figure 6. Production from other resources will continue to decline over time. By 2030, 60% of U.S. Reference Case production comes from shale resources, with the Marcellus/Utica shale accounting for 35% of total U.S. production and becoming the biggest supply source in North America. Other contributing shale resources include the Eagle Ford Shale in South Texas and Haynesville Shale in East Texas and North Louisiana.

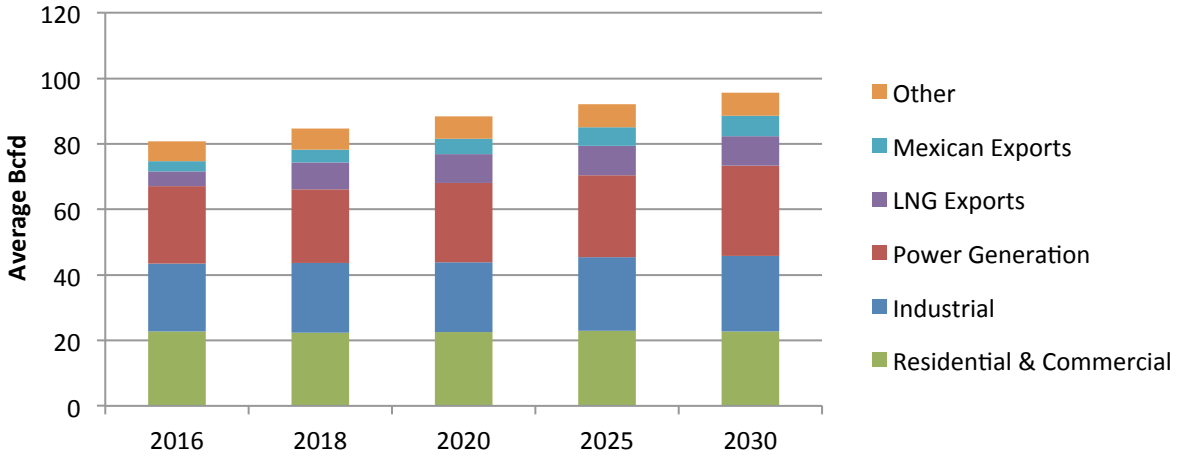
[14] Energy Velocity

Figure 6. Projected U.S. Natural Gas Production by Basin – Reference Case



In the Reference Case, total U.S. natural gas demand grows 20 Bcfd by 2030. The primary drivers for natural gas demand growth are exports, power generation, and industrial demand, as shown in Figure 7. Residential and commercial sector demand stays relatively constant at 23 Bcfd, with long-term economic and population growth largely offset by declines in per-customer usage resulting from sustained efficiency gains. Industrial sector demand is expected to be boosted by petrochemical industrial expansions, especially in ethanol and ethylene capacity. By 2022, industrial demand is expected to be 2 Bcfd, or 10%, higher than 2015 levels. However, with U.S. natural gas prices rebounding to exceed $5.00 per million Btu, the relative competitiveness of natural gas for the industrial use moderates, with an additional 1 Bcfd growth by 2030.

Figure 7. Projected U.S. Natural Gas Consumption – Reference Case



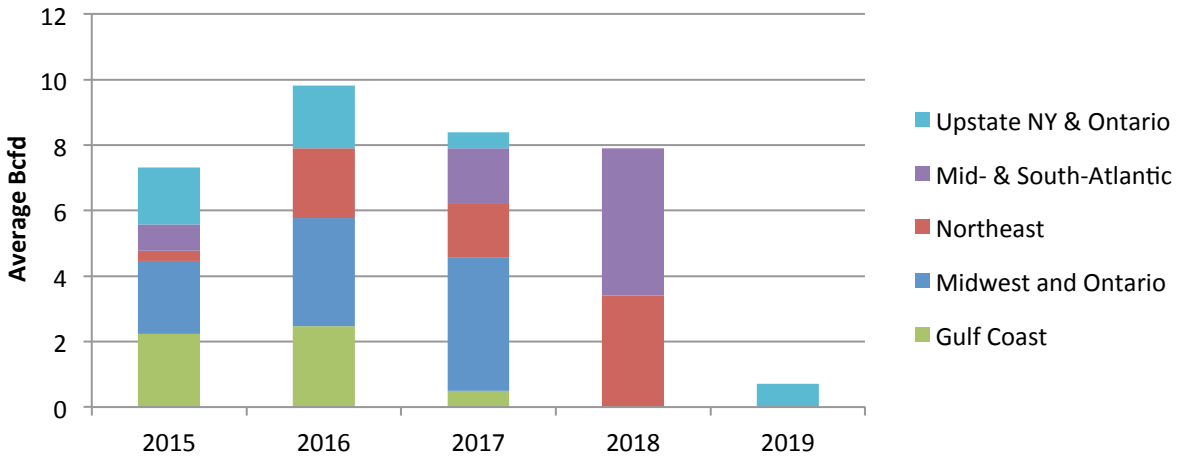
Power sector gas demand in the Reference Case grows steadily as a result of continued electric demand growth over time. With over 40 GW of projected coal unit retirements in the Reference Case between 2016 and 2020 due to MATS and relative fuel prices, electric demand growth is projected to be met increasingly by increased utilization of existing gas-fired units and the addition of new gas-fired capacity. Renewable generation competes with gas as a result of renewable portfolio standards in some states, and on an economic basis over time in select states, but gas remains the dominant fuel source for generation through 2030.

The largest projected driver of gas demand growth through 2020 in the Reference Case is exports, including both exports to Mexico and from LNG terminals. Exports to Mexico are motivated by Mexico's policy of converting oil generation to natural gas. More than 10 Bcfd of incremental pipeline take-way capacity have

recently been completed or are under construction from Texas and Arizona to Mexico. Natural gas exports sourced in the United States remain a robust, cost-effective alternative to Mexican power generation under the assumed long-term oil price of $75/Bbl. The number of LNG facilities that may eventually enter the market remains highly uncertain. Based on the assessment of world LNG demand and other international sources of LNG supply, this study projects completion of a total of 10 U.S. export facilities between late 2015 and 2021 (eight on the U.S. Gulf Coast, and two on the East Coast), exporting a total of 11 Bcfd by 2025.

There are currently over 40 announced pipeline capacity projects (new pipeline construction, reversal of existing pipeline capacity, or some combination) proposed for the Marcellus/Utica, driven largely by the rapid growth of shale gas production (that is, "production push" rather than "demand pull"). The total proposed pipeline capacity out of Marcellus/Utica exceeds 34 Bcfd by 2020 (Figure 8).

Figure 8. Announced Pipeline Expansions out of the Marcellus/Utica to Select Markets



Most of the pipeline capacity needed to get Marcellus/Utica supply to southern markets (South Atlantic, Gulf Coast industrial facilities, and LNG export terminals) can be met by reversal of existing pipeline capacity, which can be done at a relatively low cost.

The Reference Case indicates that significant investments in incremental pipeline capacity will be required to support growth in natural gas supply and demand. The scenario indicates the need for nearly 24 Bcfd of transportation capacity with 300,000 inch-miles[15] of new pipeline by 2030 at a total cost of more than $47 billion (Figure 9). Over 75% of the projected pipeline additions are concentrated in the next five years (2016 to 2020); of those additions, about 90% (236,000 inch-miles and nearly $37 billion in capital expenditures) are associated with currently planned pipeline projects. By comparison, between 2005 and 2014, capital expenditures on new natural gas pipelines in the United States totaled approximately $56 billion, with annual expenditures ranging from $1.9 billion to $13.4 billion.[16]

[15] Inch-mile estimates are based on the projected length of the pipelines added and their diameter; e.g., a 100-mile pipeline that is 36 inches in diameter equals 3,600 inch-miles. While natural gas infrastructure discussions typically focus on changes in delivery capacity (incremental Bcfd added), the inch-mile metric is critical to projecting capital expenditures, since the incremental Bcfd alone is not sufficient to estimate the cost of the added pipeline.

[16] Based on EIA's Natural Gas Pipeline Projects database; includes costs for inter- and intra-state pipelines completed between 2005 and 2014. Annual costs were summed based on reported year of completion. (http://www.eia.gov/naturalgas/pipelines/EIA-NaturalGasPipelineProjects.xls)

Figure 9. Projected U.S. Pipeline Infrastructure Requirements, 2016-2030

	New Pipeline Added (Thousands of Inch-Miles)	Net Increase in Pipeline Capacity (Bcfd)	Capital Expenditures (Billion $)
Reference	306.0	23.8	47.4
Incremental Infrastructure Requirements (versus Reference Scenario)			
CPP	9.1	3.4	1.4
Low Gas Price	20.4	7.3	3.2

The vast majority of the near-term plans for additional pipeline capacity are associated with the rapid growth of shale gas production, principally in Marcellus and Utica play areas stretching from West Virginia up through Ohio and east into Pennsylvania. There are currently over 40 announced projects to increase capacity out of the Marcellus/Utica area, most with proposed start dates of 2018 or earlier. These projects have been prompted by gas producers' desire for increased access to liquid price points and markets, and gas consumers' desire for access to abundant and attractively priced gas supplies. Because a significant portion of the demand growth is in markets in close proximity to the Marcellus/Utica area, the new pipelines cover shorter distances, relative to the long-distance pipelines originally built to carry gas from the Gulf Coast and Midcontinent area to the Midwest and Northeast. In fact, plans are in place to repurpose much of the Northeast's existing inbound pipeline capacity to transport gas out of Marcellus/Utica. The repurposing of existing pipelines reduces the amount of new pipeline construction required to meet market growth.

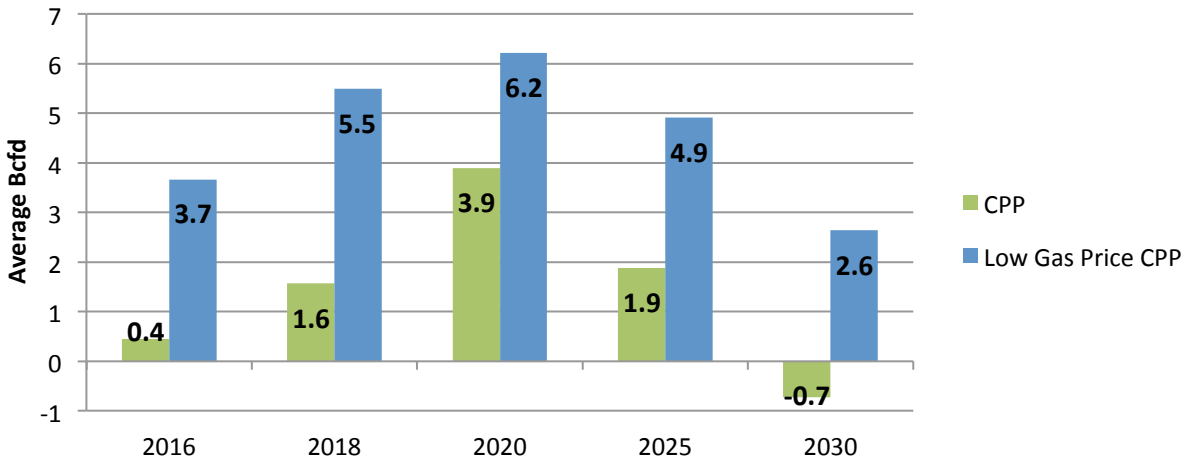
RESULTS FROM CPP AND LOW GAS PRICE CPP CASES

Both the CPP Case and the Low Gas Price CPP Case indicate a net increase in U.S. power sector gas demand relative to the Reference Case in 2020 (Figure 10). In the CPP Case, 2020 demand is 3.9 Bcfd higher, while in the Low Gas Price CPP Case demand is 6.2 Bcfd higher.[17] Compared to gas demand in the Reference Case, these changes equate to increases of 4% and 7%, respectively. After 2020, however, the incremental changes in demand decrease over time due to impacts from the other CPP compliance options, primarily reduced electricity load growth due to the assumed increase in end-use efficiency. By 2030, gas consumption in the CPP Case is actually 0.7 Bcfd lower than in the Reference Case, and the incremental gain in the Low Gas Price CPP Case is reduced to 2.6 Bcfd.

Compared to the Reference Case, the additional natural gas demand resulting from the CPP increases total capital expenditures for pipelines by between $1.4 billion (in the CPP Case) and $3.2 billion (in the Low Gas Price Case), an increase of between 3% and 7%. Because most of the incremental gas demand growth in these scenarios occurs before 2025, almost all of the additional expenditures are in the first 10 years.

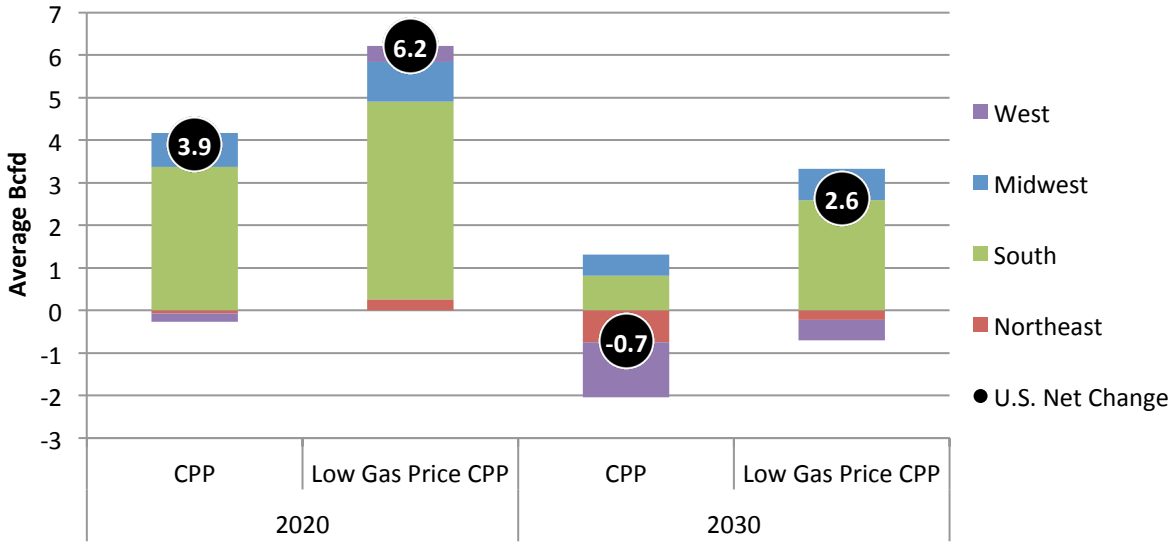
[17] The model not only allows for compliance action to take place during the compliance period, but also in advance of the complicance period beginning in 2020, and the model predicts some coal to gas switching will occur prior to 2020.

Figure 10. Net Change in U.S. Power Sector Gas Demand, Relative to Reference Case



The changes in projected power sector gas consumption under the CPP scenarios vary significantly by region (Figure 11).[18] Through 2020, consumption increases are concentrated in the South and Midwest, where the bulk of incremental coal retirements occur, with small decreases in the Northeast and West. By 2030, lower gas demand in the CPP Case in the Mid-Atlantic, Northeast and West more than offsets the increases in the South and Midwest, resulting in a net decrease in U.S. consumption. Continued assumed growth of energy efficiency across the United States in the CPP cases reduces the reliance on gas as an alternative to higher emitting coal-fired generation.

Figure 11. Regional Changes in Power Sector Natural Gas Demand, Relative to Reference Case



The projected incremental changes in pipeline infrastructure in the two alternate cases generally reflect the changes in gas consumption (Figure 12). The CPP Case requires an additional 4% in pipeline expansion beyond what is already added in the Reference Case between 2016 and 2020 and no incremental requirement beyond the Reference Case additions after 2020. Similarly, the Low Gas Price CPP Case requires a 6% increase in pipeline by 2020 and an 8% increase between 2021 and 2030 relative to the Reference Case (7% over the whole period). The primary driver of this outcome is that the Reference Case already includes planned pipelines to

[18] Regions used throughout the report are U.S. Census regions; see https://www.census.gov/geo/reference/gtc/gtc_census_divreg.html for definitions.

connect incremental production in the Northeast (from Marcellus and Utica) to neighboring markets in the South and Midwest (Figure 12). Additionally, the planned reversal of existing pipelines from the Northeast to the South and Midwest provide incremental capacity to serve these markets at a relatively low cost.

The projected inch-mile additions in all of the cases fall within the range of historical expansion of U.S. gas infrastructure. Between 2005 and 2014, the system added a total of 487,000 inch-miles, ranging annually from 7,000 to 120,000 inch-miles, as compared to a total 15-year total of just under 330,000 inch-miles in the Low Gas Price CPP case.[19] The largest consecutive five-year block of additions between 2005 and 2014 totaled almost 390,000 inch-miles, as compared to a projected five-year expansion of 250,000 inch-miles in the Low Gas Price CPP case between 2016 and 2020.

Figure 12. Incremental Pipeline Infrastructure Requirements in CPP Cases

	2016-2020	2021-2030	Total, 2016-2030
Reference			
Pipeline, Thousands of Inch-Miles	236.3	69.7	306.0
Capacity, Bcfd	21.3	2.5	23.8
Capital Expenditures, Billions of $	36.6	10.8	47.4
CPP, Incremental Requirements versus Reference			
Pipeline, Thousands of Inch-Miles	9.1	0.0	9.1
Capacity, Bcfd	3.5	0.0	3.5
Capital Expenditures, Billions of $	1.4	0.0	1.4
Low Gas Price CPP, Incremental Requirements versus Reference			
Pipeline, Thousands of Inch-Miles	14.5	5.9	20.4
Capacity, Bcfd	5.7	1.7	7.3
Capital Expenditures, Billions of $	2.3	0.9	3.2

Pipeline capital expenditures under the CPP vary significantly, depending on the assumed gas prices (Figure 13). In the CPP Case, which has gas prices similar to those in the Reference Case, almost half of the incremental capital expenditures ($0.6 billion, 5%) are in the Northeast. However, in the Low Gas Price CPP Case, increased coal retirements in the Midwest require an addition $1.2 billion (11%) capital expenditure to provide sufficient gas supply for that region.

Figure 13. Projected Incremental Regional Capital Expenditures from 2016-2030, in Billions of Dollars

	Northeast	South	Midwest	West	U.S. Total
Reference	11.2	16.1	10.6	9.5	47.4
Incremental Infrastructure Requirements (versus Reference Scenario)					
CPP	0.6	0.4	0.0	0.3	1.4
Low Gas Price CPP	0.8	0.8	1.2	0.3	3.2

[19] EIA Natural Gas Pipeline Projects database, op. cit.

CONCLUSIONS

Over the past decade, new inter- and intra-state natural gas pipelines in the United States totaled roughly 487,000 inch-miles, with an associated capital expenditure of approximately $56 billion.[20] This analysis (along with prior studies from EPA[21] and DOE[22]) suggests that total natural gas pipeline additions and associated expenditures over the next 15 years (2016 to 2030) will be less than those of the previous 10 years with or without the CPP. That would be true even if gas prices were to remain particularly low over that 15-year period. In fact, incremental pipeline additions and expenditures (above the Reference Case) through 2030 are relatively low for both CPP scenarios, ranging from 3% to 7%.

The pace of investment in new pipeline capacity over the past decade suggests that the projected future investments are well within the capabilities of the industry with or without the CPP. This finding remains true even in a future with unexpectedly lower gas prices and higher gas demand. This conclusion is reinforced by the fact that numerous competitive options for emission reduction are available in the marketplace, thus reducing the risk of heavy dependence on natural gas for compliance.[23]

There are three key factors that explain this outcome:

- First, a large number of pipeline projects are already in the planning stages to expand capacity over the next three to five years. These planned projects are sufficient to meet both the anticipated growth in gas demand in the Reference Case (that is, demand growth not related to the CPP) as well as much of the incremental demand in the CPP cases.

- Second, the assumed increase in energy efficiency in the CPP cases reduces electric load growth relative to the Reference Case. Because electric load growth is lower, power sector gas demand in the Northeast and West regions is actually lower in the CPP Case in 2030 than in the Reference Case, and only slightly higher than the Reference Case in the CPP Low Gas Price Case.

- Third, while Midwest and South power sector gas consumption is projected to increase in both CPP cases, these areas are relatively close to incremental gas supplies (principally the Marcellus and Utica shales). The proximity of the incremental gas demand to the source of the incremental supplies and the reversals of existing pipelines (moving gas from Marcellus/Utica to the Midwest and South on existing pipelines) reduces the amount of new pipeline and capital expenditures required.

It should be noted that this analysis did not include an examination of daily variability in demand and pipeline flows. This assessment's projections are derived from an examination of changes in annual and monthly gas consumption and inter-regional pipeline flow patterns. Natural gas pipeline companies need firm capacity commitments from shippers to build new capacity, so growth in annual average demand is a critical driver of pipeline additions. Nevertheless, as was made apparent during the winter of 2013-14, coincidental daily peaks in both power and non-power gas demand create the potential for congestion on the pipeline network. If daily gas demand variability increases in the future, then the need for additional pipeline capacity is potentially greater than estimated here. Some aspects of CPP compliance, such as increased energy efficiency and demand response, could reduce daily demand variability. Other aspects, such as increasing renewable generation, may

[20] EIA Natural Gas Pipeline Projects database, op. cit.
[21] U.S. Environmental Protection Agency June 2014, op. cit.
[22] "Natural Gas Infrastructure Implications of Increased Demand from the Electric Power Sector," Department of Energy, February 2015.
[23] Competitiveness of Renewable Energy and Energy Efficiency in U.S. Markets, AEE Institute, June 2015. Available at: http://info.aee.net/competitiveness-of-renewable-energy-and-energy-efficiency-in-us.

increase or decrease daily variability. Wind and solar generation are inherently variable, but higher renewable generation could potentially reduce or replace gas demand, as was seen during the polar vortex of 2014. So the net impact of the CPP on daily demand volatility is unclear.

Furthermore, it should be noted that the analysis does not capture the evolution of certain technologies and operational techniques that are changing and will continue to change the relationship between gas demand and infrastructure needs. Market incentives, such as ISO New England's Pay for Performance rules, can reduce the need for pipeline infrastructure to meet periods of peak demand.[24] At the same time, natural gas storage, gas demand response, and gas and electric energy efficiency, which may expand under the CPP, reduce the need for pipeline expansion.

[24] http://www.iso-ne.com/committees/key-projects/fcm-performance-incentives

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