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POLICY ANALYSIS

Commodity Market Impacts of EPA's Clean Power Plan

On June 2, 2014 the Environmental Protection Agency (EPA) released its draft Clean Power Plan (CPP), a proposed rule to regulate carbon dioxide from the nation's existing fossil fuel-fired generation facilities. As the central pillar of the Obama Administration's strategy for addressing climate change, the draft rule's release was both highly anticipated and contentious. New York-based economic research firm Rhodium Group (RHG) and Washington, DC-based think tank the Center for Strategic and International Studies (CSIS) have partnered to analyze the energy sector implications of the proposed rule. This note focuses on potential commodity market impacts, particularly coal and natural gas. Full energy market impact analysis is available on the CSIS web site.

Understanding the CPP: Under EPA's proposal, states would be required to reduce carbon dioxide emissions from existing power plants between 2020 and 2030. While EPA sets the targets, states choose how they will comply. Once the EPA's rule is finalized this summer, states will have one year to develop implementation plans, or up to three years if submitting a plan in coordination with other states. The earliest the rule could take effect is January 1, 2020, though legal challenges could result in delays.

What the CPP means for commodity markets: While natural gas-fired power plants are regulated under the proposal, the level at which the emission standards are set would incentivize more natural gas generation, not less. The exact impact of the CPP on the country's generation mix will depend on any changes between now and the final and implementation decisions made by the states, but under any foreseeable scenario, natural gas demand will increase, with potentially significant upside for domestic gas producers. On the flip side, coal-fired power generation will likely take a hit, as will domestic coal production.

What market developments could mean for the CPP: Given the rapidly changing nature of US energy markets, we stress-tested our findings against alternative natural gas resource scenarios, as well as a scenario in which US LNG exports exceed current expectations. In all scenarios, increased natural gas generation remains the most cost-effective way to meet the CPP targets within the electric power sector, provided the gas can be delivered on time and in sufficient quantities. This highlights the need for additional natural gas pipeline infrastructure.

What comes next: EPA is working through the 1.6 million comments they received on the CPP proposal and is still targeting a summer release of the final rule. Significant modifications are expected, including the timing and level of the interim goals (the average emissions level states need to hit between 2020 and 2029) and the methodology for setting state targets. While these changes will no doubt alter the commodity market impact of the rule, we still expect the CPP to significantly increase US natural gas demand.

UNDERSTANDING THE CPP

On June 25, 2013, President Obama announced the Climate Action Plan (CAP), the first comprehensive US plan for addressing climate change. Because power plants are the largest single source of greenhouse gas (GHG) emissions in the US (32 percent of the US total in 2012), President Obama made regulating GHG emissions from power plants a central pillar of the CAP. The CAP and a subsequent Presidential Memo directed EPA to issue rules that would limit CO_2 emissions from new and existing power plants under the authority of Section 111 of the Clean Air Act (CAA).

EPA has been regulating CO_2 emissions from various mobile and stationary sources since 2010, following a 2007 Supreme Court ruling that obligated EPA to regulate GHG emissions if it found that they posed a threat to public health and public welfare (EPA issued a so-called endangerment finding with regard to GHGs in 2010). EPA first turned to CO_2 emissions from the electricity sector in 2012, when it issued a proposed rule for new fossil-fired power plants under Section 111(b) of the CAA. That proposal was never finalized. In line with the Presidential Memo, EPA issued a new proposal for new fossil power plants on September 20, 2013, and on June 2, 2014 EPA also issued a proposal under section 111(d) of the CAA to set emission limitations on existing fossil-fired power plants. The comment period closed on December 1, 2014 and EPA has stated it hopes to finalize the rule this coming summer. The proposed rule calls on states to submit implementation plans one year after the rule is finalized (or up to three years for states submitting multi-state plans). After that, the EPA has one year to approve these plans. Compliance commences, at the earliest, January 1, 2020. Legal challenges (including some that have already been filed) are a certainty and may further slow the implementation process.

EPA's draft guidelines

EPA's proposal directs states to design and implement plans that put enforceable CO_2 emissions standards on existing fossil- fuel-fired power plants (including coal steam, oil steam units, gas steam units, and natural gas combined-cycle units) based on EPA's emission guidelines. EPA has set two emission rate (amount of CO_2 emitted, denominated in pounds per megawatt hour) goals that each state must meet. States are allowed but not required to convert these rate-based goals into mass-based goals. The first must be achieved on average between 2020 and 2029. The second, final emissions rate must be met by 2030 and each year thereafter. For example, under the current draft proposal, Texas has to meet a goal of 853 pounds of CO_2 per megawatt hour on average between 2020 and 2029, and 791 pounds of CO_2 per megawatt hour in 2030 and every year thereafter. However, EPA is silent regarding the possibility of implementing more stringent emission rate goals after 2030.

When EPA sets a new emissions standard for a stationary source under the CAA, it must determine the "degree of emission limitation achievable through the best system of emissions reduction which (taking into account the cost of achieving such reduction and any non-air quality health and environmental impact and energy requirements) the [EPA] Administrator determines has been adequately demonstrated." This "best system of emissions reduction" is commonly referred to as BSER. In its CPP proposal, EPA has concluded that the BSER is a host of cost-effective actions that plant owner-operators, states, and other actors can take to reduce CO_2 emissions from covered sources. In the current draft version of the CPP, BSER is comprised of four building blocks: 1) efficiency gains at the individual power plant; 2) re-dispatch of generation from coal plants to existing natural gas plants; 3) shifting generation away from existing fossil generating units to renewables or nuclear; and 4) end-use energy efficiency.

In order to set the state-specific emissions rate guidelines, EPA applied its BSER determination to each state, taking into account each state's fleet of existing plants covered by the rule and the availability of cost effective emissions reductions from each of the four building blocks. EPA calculated the level of reductions in emission rates achievable from each state's existing fossil generation fleet under each of the four building blocks and then added the total emissions reductions from each building block to get the total rate standard. The product is a state-specific emission rate performance level that existing fossil fuel power plants across the state must meet on a fleet-wide basis. The emission rate is an annual average across a state's entire covered fossil fleet; it need not be met by each individual fossil unit in a state.

As implementers of the actual performance standards on existing power plants, states also have enormous flexibility and discretion in setting enforceable standards of performance and choosing how to achieve the emissions reductions. In its proposed rule, EPA is agnostic as to which policies states should pursue to meet the required performance levels and has not directed states to take any one particular action or deploy any specific technology. States can use some, all, or none of EPA's proposed building blocks. If the state chooses to meet its rate standard entirely through demand-side energy efficiency and deployment of renewable resources, it is allowed to do so. Alternatively, a state could meet the goals through expanding fuel-switching from coal to gas. EPA has signaled that it is open to essentially any steps that states take, as long as their plans reduce emissions from covered sources and meet EPA specifications for stringency (meaning the covered power plant fleet in the state meets the performance level on average), enforceability, and other procedural metrics.

In addition to flexibility in terms of how states can meet their assigned performance levels, the CPP also includes the option for states to cooperate with any other state(s) they choose and will allow states to submit multi-state compliance plans. Under the CPP, states may jointly submit a multi-state plan that imposes consistent standards across the combined multi-state jurisdiction. In practice, this requires an adjustment to the assigned state performances levels by calculating a weighted average emissions standard. The result is a single standard that applies to all covered generators across the multi-state footprint.

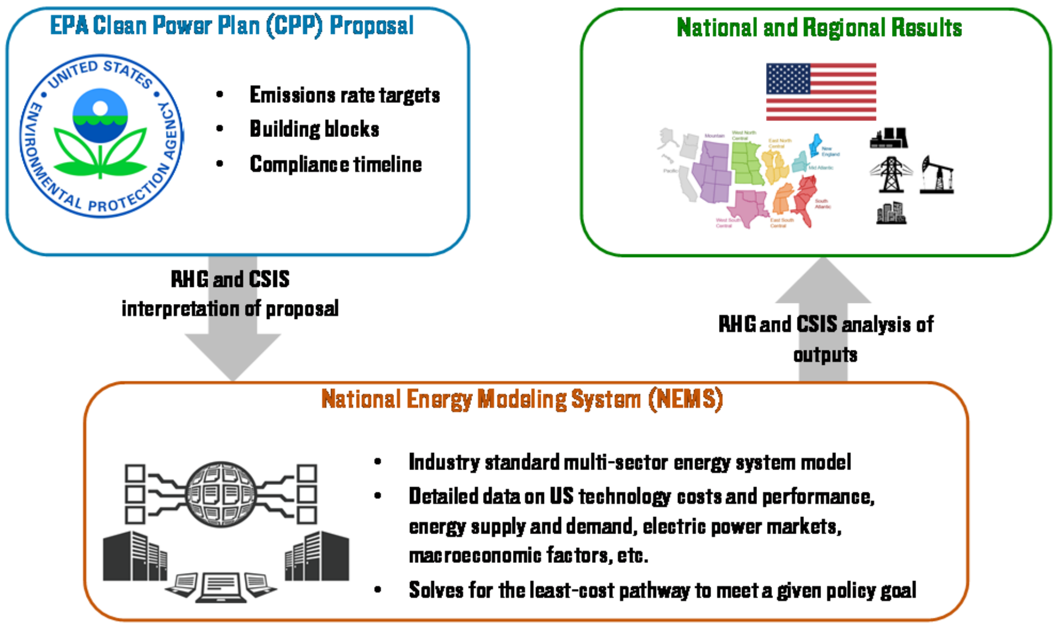
Cooperation across states allows for regulatory consistency across a broader share of the US power generation fleet and expands the number and diversity of abatement options available to covered generating units, lowering the costs of compliance overall. Some states, such as members of the Northeast Regional Greenhouse Gas Initiative (RGGI), already cooperate in multi-state CO_2 reduction programs. Under the CPP, multi-state cooperation is not required, although EPA has proposed to give states pursuing this option more time to submit an implementation plan. There are no restrictions in the CPP as to which states may or may not cooperate with each other.

Assessing the impact

To assess both the upstream and downstream impacts of the CPP, we employed RHG-NEMS, a version of the National Energy Modeling System (NEMS) maintained by the Rhodium Group (RHG). Developed by the Energy Information Administration (EIA) and used to produce the EIA's Annual Energy Outlook (AEO); NEMS is a leading computer-based modeling system used to project future energy supply, demand, and price conditions in the United States; and to analyze the impact of macroeconomic, policy, market, or technology changes on those projections. As a comprehensive model of the US energy system with detailed electric power sector and upstream oil, gas, and coal production representation, NEMS is particularly well suited to analyzing the broader energy market impact of the CPP (Figure 1).

It is important to note that we model EPA's *proposed* rule, which is subject to change as it goes through the federal rulemaking process. Indeed, in October EPA issued additional information for public comment through a Notice of Data Availability (NODA) that explores potential guideline approaches that differ from the June proposal. Once the rule is final, however, the ultimate energy system and economic impacts will depend a great deal on how states choose to meet the ultimate emission performance targets set by EPA. Given the large amount of flexibility EPA provides the states in the CPP, it is impossible to model each possible compliance pathway.

Figure 1: Modeling approach



As a result, we crafted four policy scenarios that reflect two of the most significant implementation choices states will need to make.

> 1) *The level of cooperation between states*. We focus on cooperation as one of the key design elements because broader compliance markets provide states with greater diversity of abatement options, generally lowering costs. How cooperation changes implementation costs is a major question state officials are trying to answer as they choose how to implement the CPP.
>
> 2) *Whether or not energy efficiency is included in state implementation plans*. Power sector air pollution regulations have historically focused on generation-side compliance options. The inclusion of demand-side EE is relatively novel and could have a material impact on generation system dynamics and the broader energy system.

Our four policy scenarios are listed in Table 1 below. We model all four through a tradable performance standard that allows generators to meet the emissions rate goal at least cost, given different implementation decisions. States may, of course, choose different compliance mechanisms. While not exhaustive, we believe these scenarios do a reasonable job of bounding the range of potential energy system impacts of the current proposal, assuming it is implemented on time, and by all states. At the end of this note we discuss the prospects for modification and/or delay.

Table 1: Policy scenarios

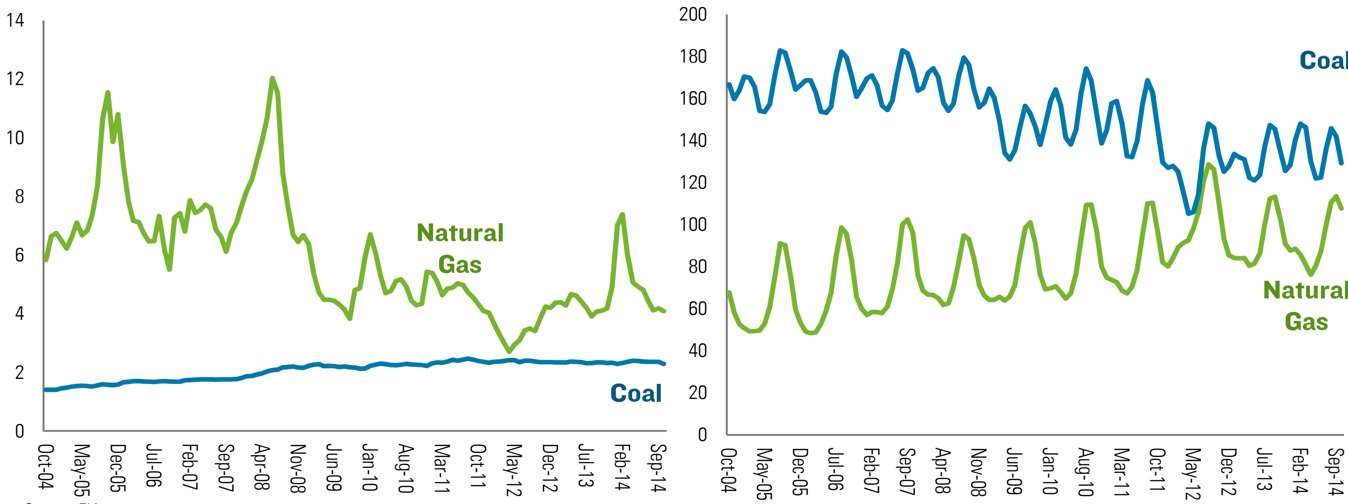
	National Cooperation	Regional Fragmentation
No States Include EE in Plans	National w/o EE	Regional w/o EE
All States Include EE in Plans	National w/ EE	Regional w/ EE

WHAT THE CPP MEANS FOR COMMODITY MARKETS

Thanks to the shale revolution, cheap natural gas prices have already begun transforming the US power generation landscape. Between 2008 and 2012, average delivered natural gas prices at US power plants fell from $8.9 per MMBTU to $3.5 (Figure 2). This resulted in substantial coal-to-gas switching in the power sector as natural gas combined cycle plants out-competed coal plants in wholesale markets. In 2012, the share of total US electricity generated by coal averaged 37%, down from 48% in 2008, while natural gas's market share grew from 21% to 30%. That translated into a 6.7 billion cubic feet per day (Bcf/d) increase in natural gas consumption – two-thirds of the growth in domestic production during that period.

Figure 2: Fuel prices (LHS) and power generation (RHS)

USD per MMBTU delivered to power plants (LHS) and billion kWh, 3mma (RHS)

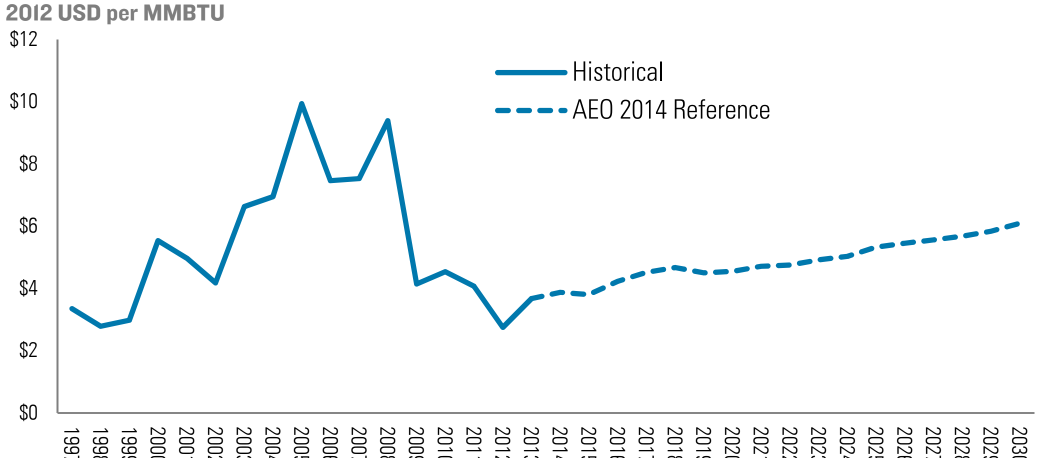


Source: EIA

Delivered natural gas prices for power generation have averaged $4.7 per MMBTU since the end of 2012, with monthly average prices getting as high as $7.1 during the 2014 polar vortex. As a result, natural gas' inroads into the power sector haven't advanced much beyond 2012 levels. At current or projected natural gas prices (either in in futures markets or by the EIA – the prices used in our analysis, see Figure 3), gas will likely fuel a significant share of new generation, but is unlikely to displace large, additional quantities of existing coal-fired power.

Figure 3: Henry Hub natural gas prices

2012 USD per MMBTU



Source: EIA

Emissions standards in the presence of cheap gas

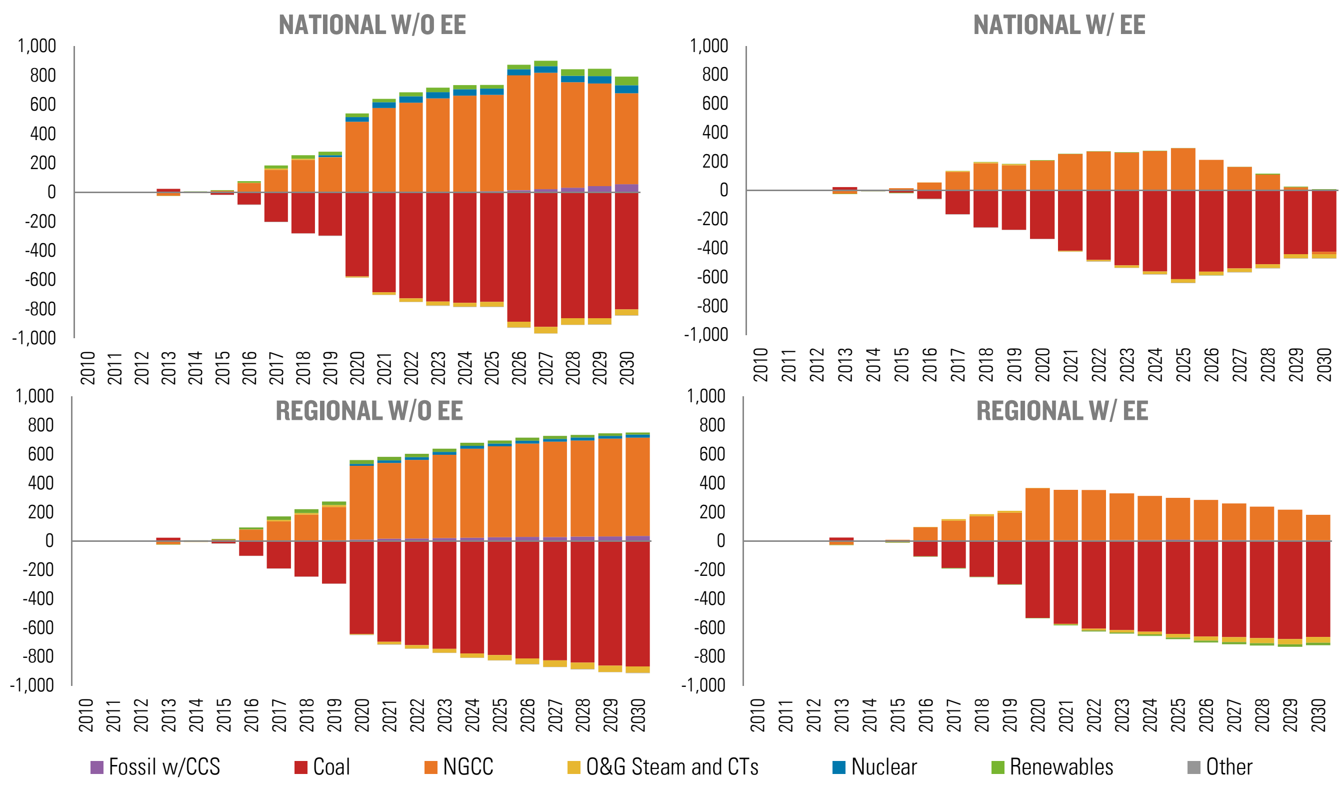
Imposing a CO_2 emission constraint in the presence low-cost natural gas, however, could significantly expand gas demand in the electric power sector. Natural gas is less carbon-intensive than coal, and the CPP shifts incentives towards lower-carbon generators. Even though zero-emitting generators like renewables receive more credit under the CPP formula than NGCC units, NGCC units are more competitive in our analysis thanks to low technology costs, low natural gas prices, and a large amount of underutilized capacity in most power markets. No matter which compliance option states choose to meet the EPA's emission rate goals, we expect a significant shift towards greater NGCC generation, largely coming at the expense of existing coal generation. In each of our four scenarios, coal-to-gas fuel switching is the most cost-effective generation-side compliance pathway – the only difference in the scenarios is the magnitude of the shift.

NGCC generation increases more if states choose not to credit EE—as much as 660 terawatt hours (TWH) (a two-thirds increase in NGCC generation from current levels) above "business-as-usual" (BAU) levels projected in the EIA's 2014 Annual Energy Outlook on average from 2020 through 2030—while coal generation declines by 770 TWH (see Figure 4). Generation from nuclear and renewables also increases above BAU in the scenarios without EE, but far less than natural gas generation (80 TWH on average from 2020 through 2030).

In scenarios where EE is included, the shift toward NGCC generation is much smaller, about 185 TWH on average in our National with EE crediting scenario (and 285 TWH in 2020 in the Regional w/ EE crediting case), and all but disappears by the end of the compliance period. With EE crediting, we see almost no change in zero-emitting generation relative to BAU. This is because the CPP does not prioritize zero emission generation options; the CPP is a *lower* emissions plan, not a *zero* emissions plan. In fact,

Figure 4: Change in electricity generation

Relative to EIA's 2014 Annual Energy Outlook, billion kwh



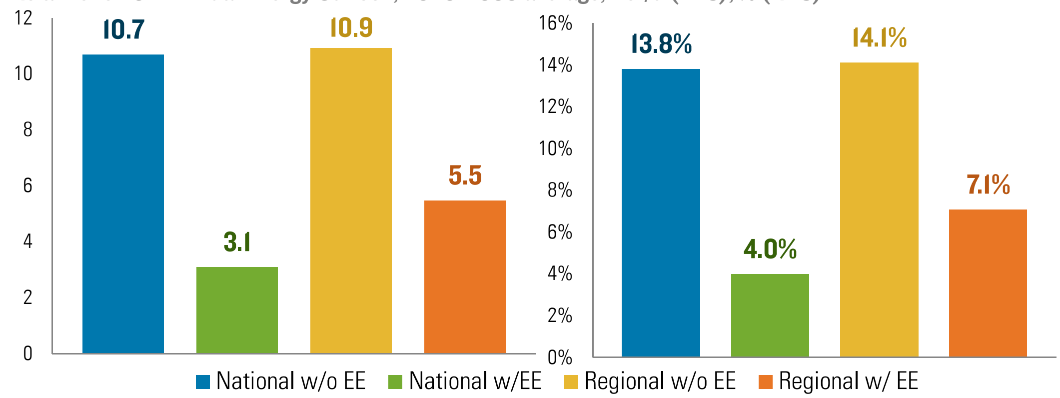
the CPP is agnostic about these options; the decision about whether to prioritize zero-emission options is left entirely to the states. If states wish to ensure that nuclear generation, distributed generation, and renewables play a role in their state's generation mix, they will need to actively prioritize nuclear, distributed generation, and renewables in their state implementation plans.

Implications for gas markets

This magnitude of coal-to-gas shift in US power generation has significant implications for domestic gas demand, production, and producer revenue. Depending on the policy scenario, the CPP could deliver between 3.1 and 10.9 Bcf/d of additional gas demand on average between 2020 and 2030, a 4% to 14.1% increase relative to the EIA's projected demand levels without the CPP (Figure 5).

Figure 5: Change in natural gas demand

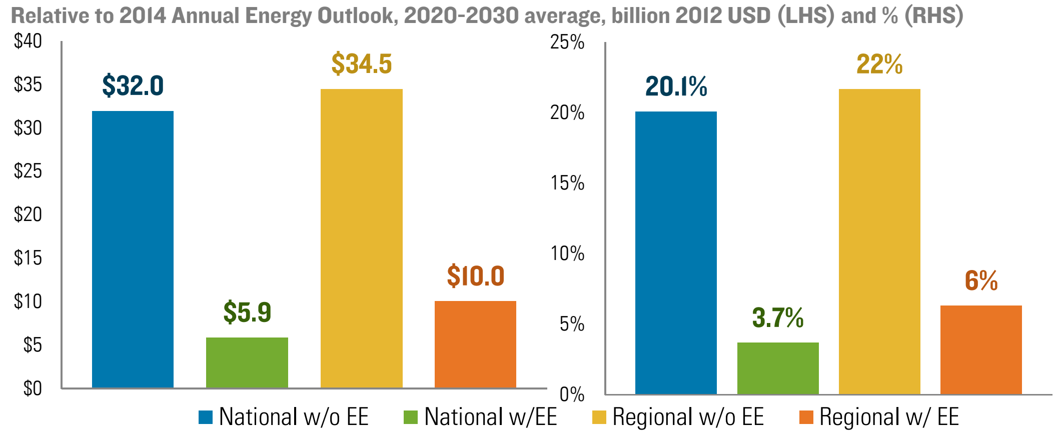
Relative to 2014 Annual Energy Outlook, 2020-2030 average, Bcf/d (LHS), % (RHS)



Given the magnitude of domestic shale resources, the vast majority of that increase in demand, in our analysis, is met through increased domestic supply, and results in a relatively small change in price. The EIA projects that absent the CPP, Henry Hub prices will average $5.27 per MMBTU in 2012 dollars between 2020 and 2030. In our National w/o EE scenario, an additional 10.7 Bcf/d of domestic gas demand increases Henry Hub prices, but only to $5.73 per MMBTU. This small change in price, and large change in production volume, translates into a $32 billion per year increase in gas producer revenue (in 2012 dollars) on average between 2020 and 2030, or 20.1% higher than projected in the EIA's 2014 outlook (Figure 6). Gas producers see material gains in all scenarios, though significantly smaller in those where states include EE crediting in their implementation plans.

Figure 6: Change in natural gas production revenue

Relative to 2014 Annual Energy Outlook, 2020-2030 average, billion 2012 USD (LHS) and % (RHS)

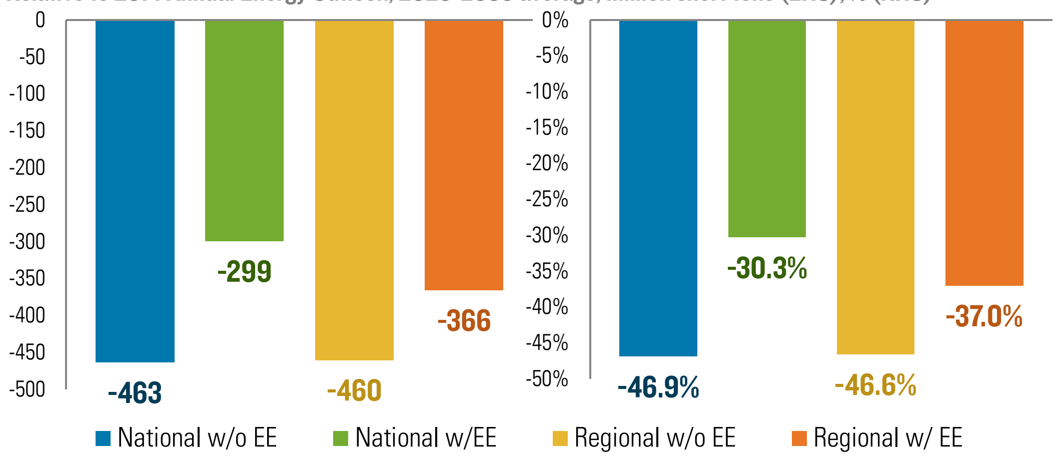


Implications for coal markets

The potential upside for natural gas producers from CPP implementation is matched by an equally significant potential downside for domestic coal producers. Depending on the implementation scenario, domestic coal demand could decline by anywhere between 299 and 463 million short tons on average between 2020 and 2030, or 30.3% to 46.9% below levels projected in the EIA's 2014 outlook (Figure 7).

Figure 7: Change in coal demand

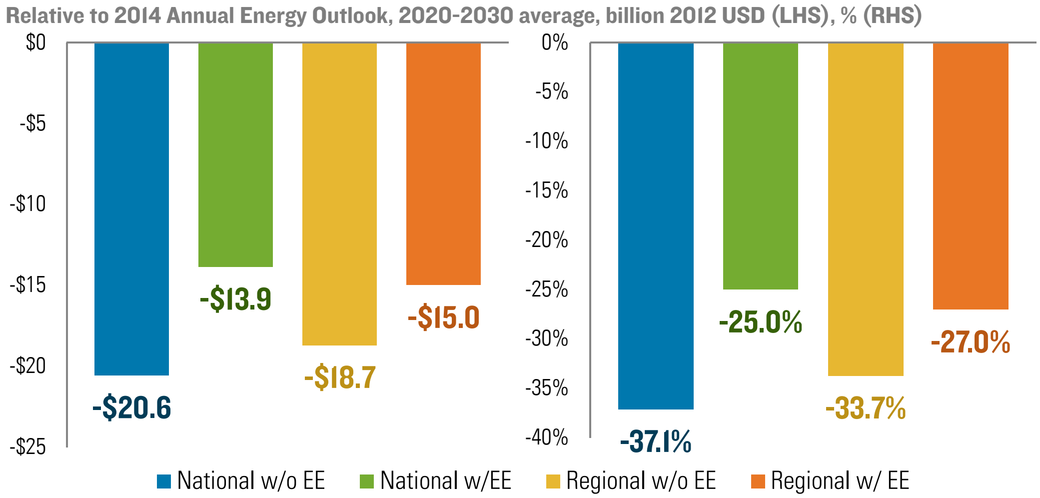
Relative to 2014 Annual Energy Outlook, 2020-2030 average, million short tons (LHS), % (RHS)



This decline in demand is born primarily by domestic producers who, absent new export capacity, have few market alternatives. At EIA's projected coal prices, the CPP could result in a $13.9 to $20.6 billion decline (Figure 8). That's 25% to 37% below levels projected in EIA's 2014 outlook.

Figure 8: Change in coal production revenue

Relative to 2014 Annual Energy Outlook, 2020-2030 average, billion 2012 USD (LHS), % (RHS)



WHAT MARKET DEVELOPMENTS COULD MEAN FOR THE CPP

The results presented above assume the domestic energy markets, absent the CPP, develop along the lines projected in the EIA's 2014 outlook. That's a bold assumption, of course, given the dramatic shifts in the energy landscape that have occurred in just the past few years. As natural gas plays a key role in meeting the CPP's emission reduction targets in our analysis, we stress-tested that finding against three alternative gas market futures:

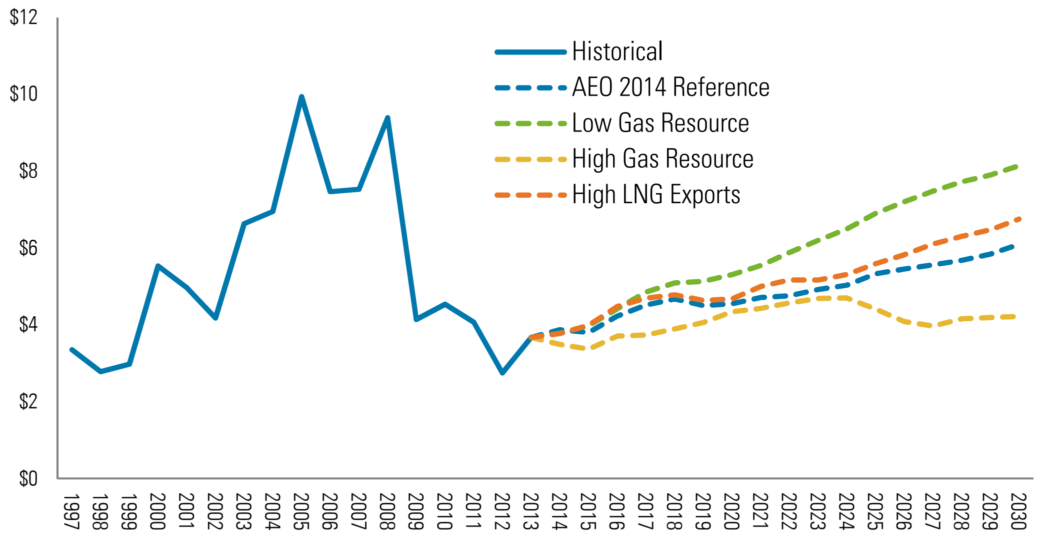
1) *High Gas Resource*: Greater than currently estimate shale gas resources and thus lower baseline gas prices.

2) *Low Gas Resource:* Smaller than currently estimate shale gas resources and thus higher baseline gas prices.

3) *High LNG Exports:* LNG exports grow to 9 Bcf/d in 2020 and 18 Bcf/d in 2030.

The gas price trajectory under each scenario is shown in Figure 9, absent the CPP.

Figure 9: Henry Hub natural gas prices
2012 USD per MMBTU



As shown in Figure 10, coal-gas switching is still the least cost pathway for CPP compliance even in a Low Gas Resource or High LNG Export world. The higher gas prices in these two scenarios reduce the magnitude of the coal-gas switch, and in the Low Resource case, provide additional room for renewables and nuclear to compete. But in the National w/o EE policy scenario, average annual natural gas production and revenue increases by 6.3%and 14% respectively between 2020 and 2030, even if the shale resource bases disappoints; that is compared to 12% and 20% under reference shale resource assumptions.

Changing natural gas resource and LNG export assumptions does not significantly alter the impact of the CPP on domestic gas prices (Figure 11). In the Low Gas Resource scenario, the CPP increases Henry Hub prices by $0.49 cents per MMBTU on average between 2020 and 2030, compared to $0.46 cents per MMBTU under current shale resource assumptions (assuming National w/o EE policy implementation). In the LNG Export scenario, the CPP-driven increase in gas prices is $0.57 per MMBTU.

If the shale resource base proves larger than currently expected (the High Gas Resource case), Henry Hub prices rise by only $0.20 cents per MMBTU on average between 2020 and 2030, compared to the reference case. This mitigates the potential upside for producers from the CPP, despite the large increase in production volumes in this scenario.

Figure 10: Change in electricity generation

Relative to 2014 Annual Energy Outlook, 2020-2030 average, billion kWh, National w/o EE scenario

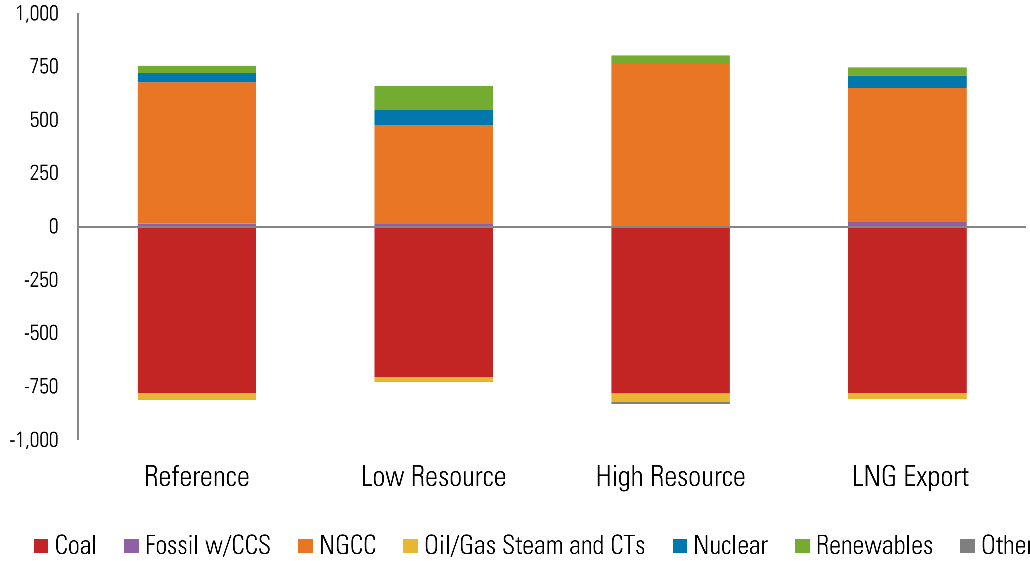
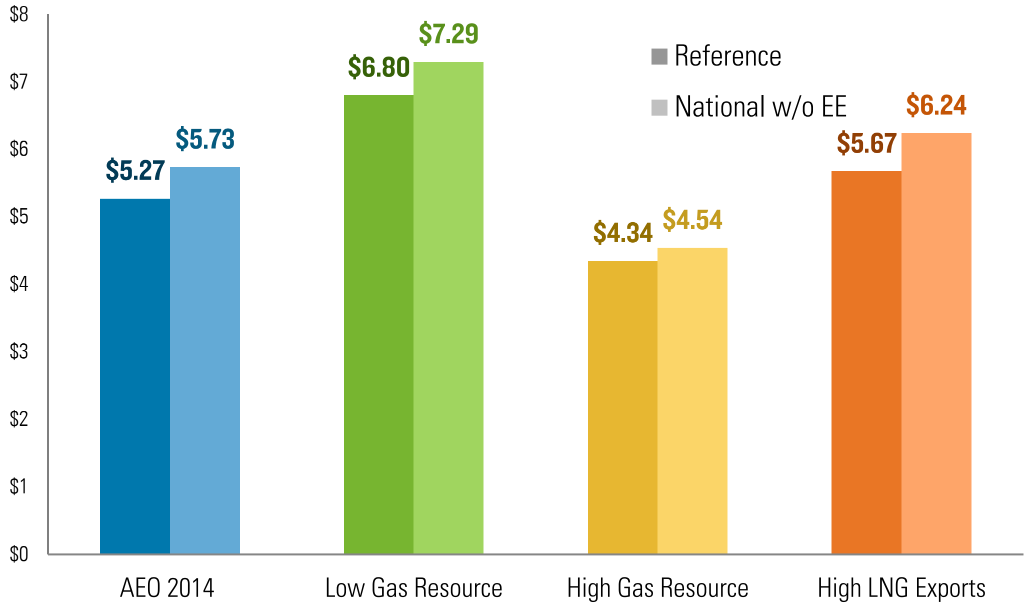


Figure 11: Henry Hub natural gas prices

2020-2030 average, 2012 USD per MMBTU



Getting the gas where it's needed

In order to seamlessly and cost-effectively incorporate more natural gas into the US electric system, the necessary infrastructure – pipelines, pumping stations, gathering lines – will need to be in place in a timely fashion. This midstream infrastructure is a critical component to making natural gas a viable choice for many of the states and regions in the US that might seek to benefit from natural gas both for its emissions reduction potential and production value.

There is some evidence that that necessary infrastructure is starting to be put in place. Between 2000 and 2011, about 14,600 miles of new natural gas pipeline capacity –

equivalent to 76.4 Bcf/d – was built to accommodate growing gas demand, including in the electric power sector. Nonetheless, according to a recent study conducted by ICF International and the Interstate Natural Gas Association of America (INGAA), over 37 Bcf/d of additional inter-regional natural gas pipeline capacity will be needed between 2014 and 2035 – that's before any CPP-driven changes in demand. The study concluded that capacity is most needed in the Northeast and Southwest, not only to accommodate production increases, but also to deal with changes in interregional trade flow. Marcellus gas production is increasingly able to meet the gas demand of New England, displacing the gas that traditionally flowed northeast from the Gulf Coast. Instead, production in the Gulf will be sent both to local markets and the Southeast for consumption, and to LNG terminals along the Gulf for export. Greater Rocky Mountain region production will be consumed on the West Coast, helping offset declines from Canada.

Table 2: Projected inter-regional natural gas pipeline capacity additions
Bcf/d

Originating region	2014-2035
US	39.9
Central	7.2
Midwest	3.5
Northeast	10.1
Southeast	7.9
Southwest	10.2
Western	1.0

Source: ICF/INGAA

Our modelling assumes that infrastructure will be financed and built to enable relatively seamless natural gas delivery, but that is far from a foregone conclusion. In the Northeast and Southwest (areas where INGAA already identified significant pipeline capacity needs), our modeling finds an increase in demand of 0.3-1.3 and 0.6-3.2 Bcf/d above the reference case, respectively, and an increase in production of 0.8-2.1 and 2.0-5.2 Bcf/d. This does not take into account infrastructure needed to move gas internally within a region. A more precise estimate of the pipeline infrastructure needs in and between each region is warranted, especially given that certain regions of the country, the Northeast in particular, are already struggling to put in place natural gas pipeline infrastructure to meet peak winter power generation demand.

WHAT COMES NEXT?

While EPA successfully issued the 111(d) proposed rule in line with the President's timeline, the final content of the rule and the timeline for finalization and implementation are much less certain. With regards to content EPA is expected to substantially revise at least three aspects of the rule it identified in its October NODA: the interim goals (both in terms of targets and implementation timeline), the methodology for calculating the building blocks, and the methodology of setting state targets. These revisions are likely to alter the energy market impacts of the rule, although we expect that natural gas will still be the primary compliance mechanism.

Even if EPA manages to finalize a rule by mid-summer – a tall order, considering the more than 1.6 million comments EPA received and is legally required to consider – legal challenges, which can commence once the rule is finalized, could delay the rule's implementation, perhaps significantly. Even if no injunction is issued by the courts, the proposal gives states until June 2016, and under certain circumstances June 2017 or June 2018, to submit implementation plans, which EPA will then take up to a year to approve. Individual state plans could also be subject to legal challenge. There is also the possibility that some states will choose not to submit plans to EPA at all or that they submit plans that do not meet EPA's criteria. Such actions could force EPA to impose federal implementation plans in each instance, though it is unclear how quickly EPA might act in such situations. This timeline is also likely to change depending on how EPA structures the final rule. Therefore, the rule is not likely to be implemented by all states until 2019 at the earliest, assuming that legal challenges or other issues do not further delay implementation. As this analysis demonstrates, once we get to the end of the implementation tunnel the total impact of the CPP will hinge on design choices made by states. We will be tracking developments at the federal and state level closely and refine our understanding of how energy markets will respond to the final CPP regime.

DISCLOSURE APPENDIX