# EPA Clean Power Plan: Costs and Impacts on U.S. Energy Markets

*Energy Ventures Analysis, Inc.*

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## 1. Executive Summary

The Environmental Protection Agency's (EPA) Clean Power Plan (CPP) proposes to regulate $CO_2$ emissions from 3,104 US fossil-fired electric power generating units under the Clean Air Act. The purpose of this study is to provide an independent evaluation of EPA's June 2014 draft proposal and its impacts on the US energy markets and future power industry $CO_2$ emissions using a more comprehensive power industry economic dispatch model than the simplified linear program model used in the EPA analysis. Given the complexities states face in implementing a $CO_2$ rate-based limit program, this study evaluates the much easier to implement mass-based limit option that states are more likely to pursue under the EPA proposal. The same state-specific mass-based limitations EPA used to develop the Clean Power Plan were adopted for this analysis.

The independent evaluation done by Energy Ventures Analysis (EVA) uncovered significant flaws in EPA's analysis that have led the agency to considerably underestimate the true compliance costs of the CPP and its market impacts. Many flaws are directly attributable to EPA's underlying assumptions about power plant process efficiency improvements, non-hydro renewable energy expansion and growth in consumer energy efficiency – assumptions that were used to calculate state emission rate limitations. EPA's assumptions are well above power industry practices and projections by the U.S Department of Energy (DOE) and independent forecasts.

This report finds that compliance costs will be substantially higher than EPA's ten-year projections (2020-2030). These additional costs (2013$) attributable to the proposed CPP include:

- Higher Wholesale Electricity Costs: **$274 Billion**
- Higher Residential/Commercial/Non-power Industrial Natural Gas Costs: **$ 80 Billion**
- Additional Capital Costs for Replacement Power Capacity: **$53 Billion**

These compliance cost projections capture only a portion of the costs not reflected in the agency's CPP projections. Additional costs not quantified include: (1) new transmission investments to access more remote high wind resource areas and react to changes in power flows, (2) additional transmission ancillary services to handle greater amounts of variable wind and solar generation, (3) higher gas rates for all customers from increasing costs for pipeline compression, and (4) GDP changes triggered by raising energy prices.

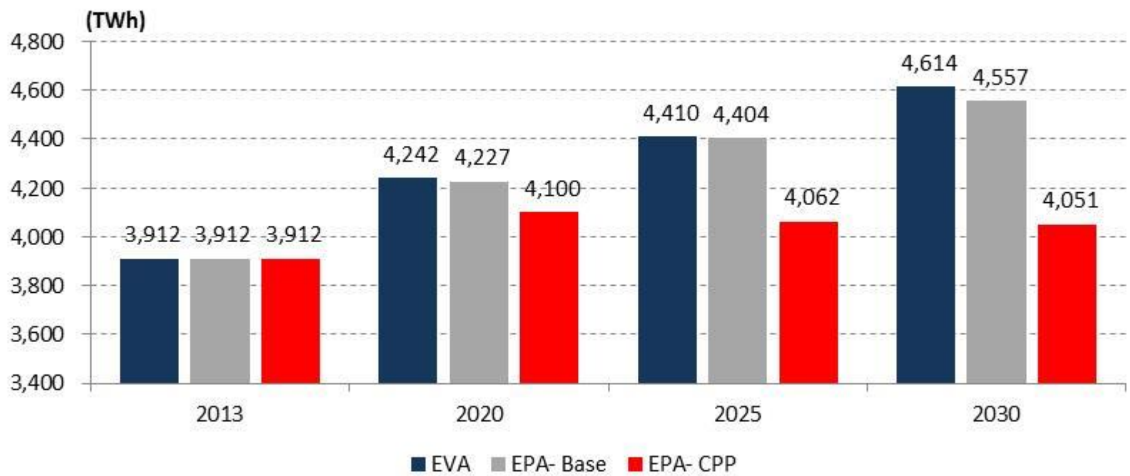
This study has assumed that the CPP can be implemented by 2020, a schedule that poses a herculean challenge on state agencies. The long timelines to adopt state authorization legislation, develop compliance plans through public comment, obtain EPA approval and plan/permit/finance/build/operate necessary transmission and generation supply projects renders EPA's timetable implausible if not impossible in most cases.

## Major Findings

### Electricity Demand

As shown in Exhibit 1.1, US electricity demand between 2020 and 2030 is expected to continue to grow 0.85%/year on average --- not decline by -0.12%/year as projected by the EPA. While power industry's multi-billion energy efficiency investments should continue, these programs are unable to entirely offset electricity demand growth from increasing population and expanding economic growth. From this one error alone, the EPA has significantly underestimated future generation needs, energy prices, required compliance strategies and their total costs.

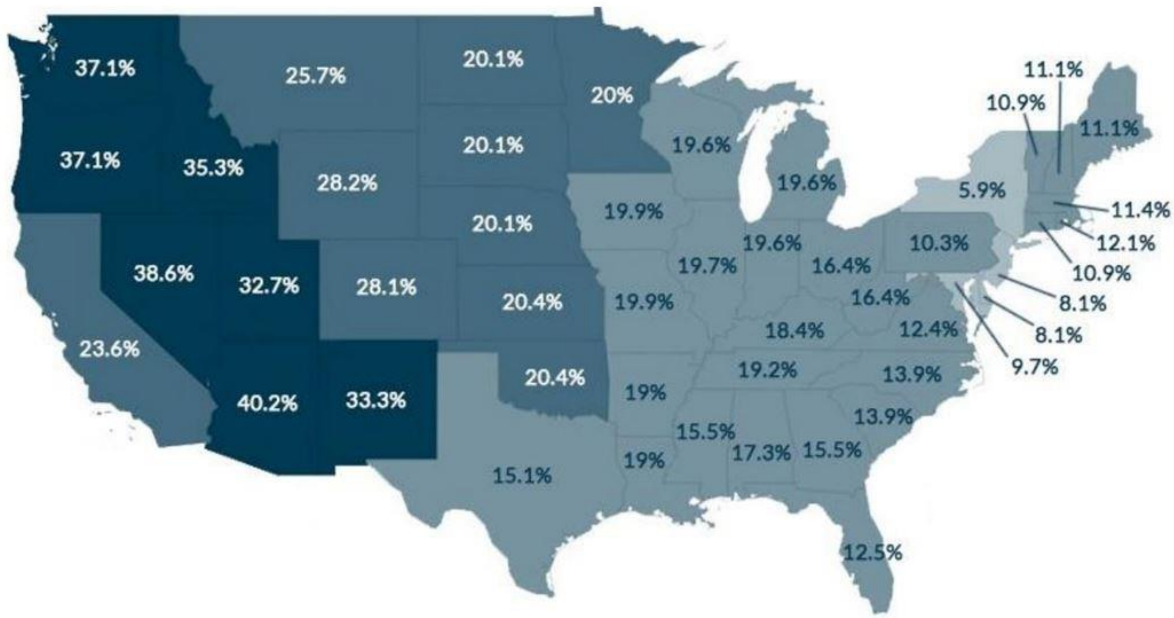
**Exhibit 1.1: Comparison of Total Generation:**




### Wholesale Electricity Costs

US wholesale power supply costs will increase by nearly $30 billion/year (2013$) from the combination of the carbon penalty, changes in fossil fuel prices and economic dispatch order. To meet CPP limitations, the power industry will incur a carbon penalty on all affected fossil fired generation starting in 2020. This penalty will be set by the value needed to change the economic dispatching order of in-state fossil-fueled generation required to meet state-specific $CO_2$ mass limitation. This $CO_2$ penalty alone will add $30-33 billion (2013$) per year to US power generation production costs across the 3,104 affected units. Exhibit 1.2 shows the average percentage increase in wholesale power prices triggered by the CPP versus a reference case without carbon regulation.

**Exhibit 1.2: Average ('20-'30) Wholesale Electricity Cost Increases (%):**

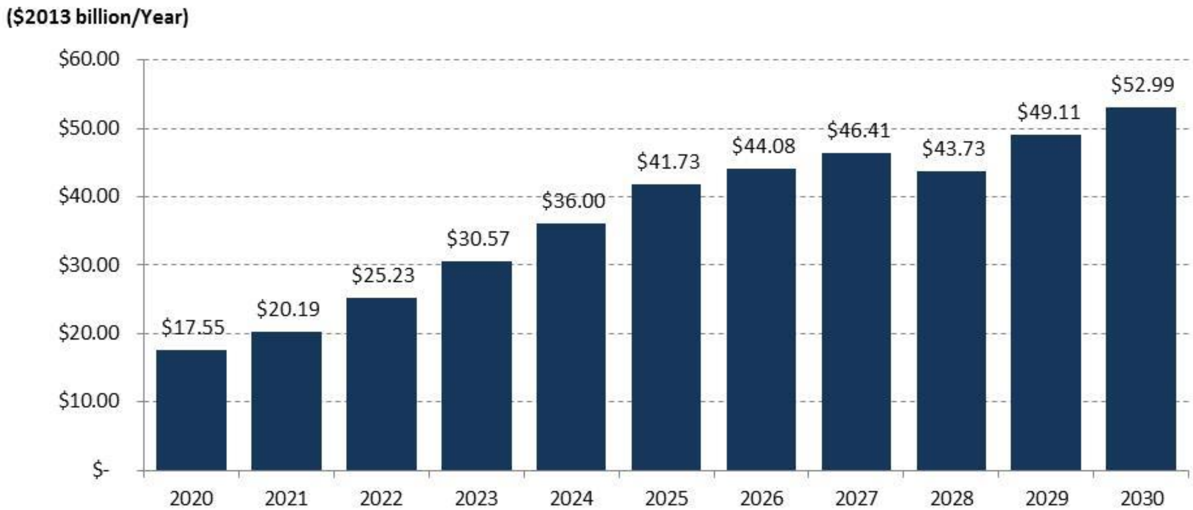



## Capital Costs of Replacing Displaced Low Cost Coal Generation

To comply, the industry must displace large amounts of low cost coal generation with natural gas combined cycle generation. This shift in generation mix will result in 15 GW of additional retirements beyond the 62 GW of retirements caused by EPA's 2012 UMATS regulation. **The CPP combined with the UMATS regulation will force 25 percent of low cost reliable coal generation capacity off the electric grid.**

To replace the generation from the retirement of an additional 14.8 GW of existing coal fired capacity (already largely paid for by ratepayers) will require building 33.3 GW of natural gas combined cycle and 8.4 GW in non-hydro renewable capacity to replace it. As shown in Exhibit 1.3, this additional new incremental replacement capacity will cost suppliers an additional $17.6 billion (2013$) in 2020 and grow to $53 billion (2013$) by 2030. Capital recovery costs (in addition to higher wholesale power costs) would be passed onto US ratepayers. Costs burdens will vary significantly by location.

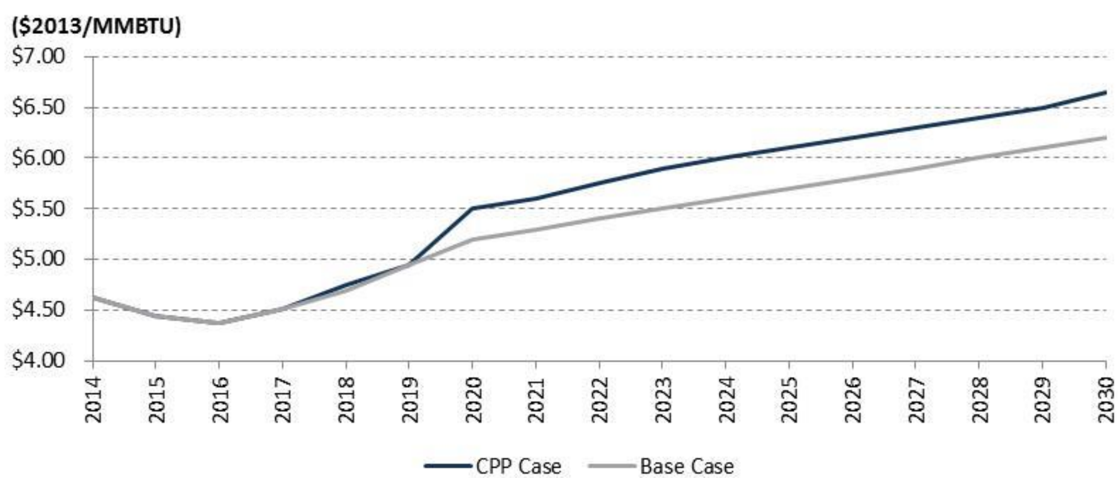
**Exhibit 1.3: Incremental Cumulative Power Capital Investment Due to CPP:**




## Additional Costs of Natural Gas for Households and Industries

The shift towards greater natural gas power will increase US natural gas consumption by 7.7 TCF. To meet this power industry demand, the natural gas commodity market price will initially rise by $0.30-0.45/MMBtu (2013$), as shown in Exhibit 1.4. This market price increase will be absorbed by not only the power suppliers but also by residential, commercial and industrial gas consumers. Overall, non-power suppliers will need to pay an additional $5-9 billion/year in higher natural gas commodity prices. In addition, natural gas price increases should also increase pipeline compression costs that will push delivered prices and costs even higher.

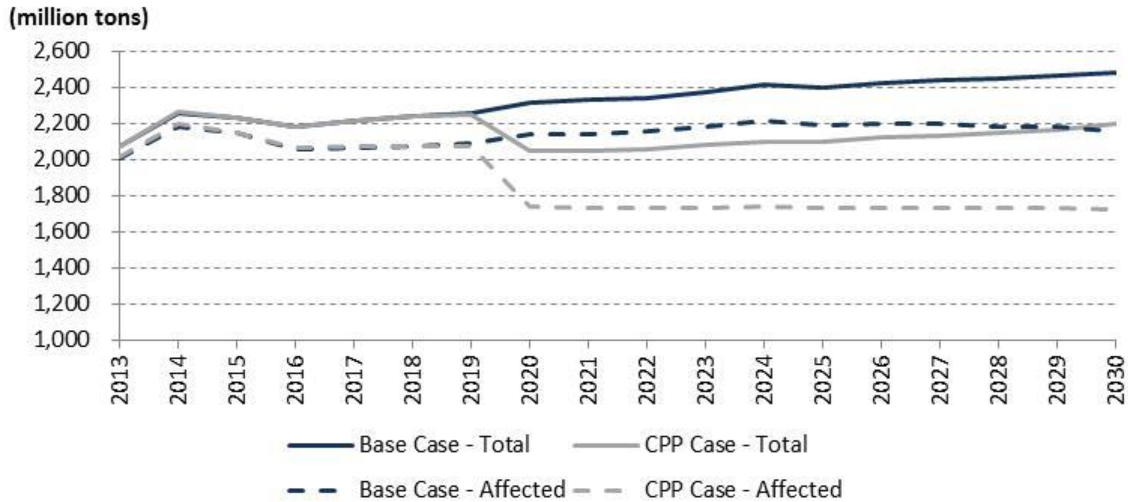
**Exhibit 1.4: Henry Hub Natural Gas Price Increase Due to CPP:**



## Emission Reductions

Overall, the CPP may reduce power industry net- $CO_2$ emissions by 270-320 million tons/year, as shown in Exhibit 1.5. The estimated reductions at existing power plants would be partially offset, however, by emissions from new sources (+170 million tons/yr. from natural gas) that would not be regulated under the CPP. To reduce power emissions to meet CPP state $CO_2$ emission rate limitations, 415-448 TWh (25%) of coal generation must be displaced—primarily by new and existing natural gas combined cycle generation (380-435 TWh) and, to a much smaller degree (1-20 TWh), by non-hydro renewable generation.

**Exhibit 1.5: Power Sector $CO_2$ Emissions by Source:**




## Additional Costs & Uncertainties

In addition to higher wholesale power costs, new generation capacity investment and higher natural gas commodity costs from the implementation of the CPP, electricity ratepayers will incur additional compliance costs that have not been quantified in this study or by the EPA. These additional costs include new transmission line investments (to access more remote areas with high wind resources, to react to changes in power flow patterns, and to cover investments needed to provide more ancillary services to handle greater amounts of variable wind and solar generation) and new pipeline investments.

This study has assumed that the Clean Power Plan can be implemented by 2020. This schedule poses a herculean challenge given the long timelines to adopt needed state authorization legislation, pass required compliance plans through public comment, gain EPA approval and plan/permit/finance/build/operate needed transmission and generation supply projects. EVA estimates between 5-10 years for such projects to move from planning to completion. Therefore the U.S. power markets would not be able to adjust and add the necessary major generation, transmission and pipeline infrastructure until after 2025; a fact the EPA did not consider in its regulatory impact analysis.

This study assumes that EPA would approve all state implementation plans that incorporate the same state base mass limitations that EPA used in the development of its state specific emission rate limitations. It should be recognized that the least cost method for meeting the state mass based limitations may not always result in also meeting the state rate based limit.

## EPA Building Block Assumptions

EPA incorporated four building blocks in its derivation of state emission rate limitations. A quick review of these building block assumptions provides insight into why EPA has overestimated the building block performance and underestimated program compliance costs.
EPA assumed that existing coal-fueled generating facilities could achieve a 6% heat rate improvement by 2020. This assumption is a combination of a 4% improvement from using best practices and a 2% improvement from capital investments. The regression analysis used by EPA to derive the 4% improvement lacks sufficient technical data and shows no indication that it accounts for differences in coal rank, boiler type and boiler age, all of which have significant effects on heat rate efficiencies. The 2% improvement relies upon a single study from January 2009. However the referenced study does not conclude that all coal boilers can improve their heat rates—let alone by 2% from 2008 levels. Additionally, EPA does not consider the impact of other environmental regulations (e.g., Mercury Air Toxic Standard) that will increase the parasitic load and reduce plant efficiencies. EPA also did not consider that these investments could also trigger new source review and require additional retrofitted environmental controls. Furthermore, the CPP as proposed would reduce the utilization of coal plants which further reduces their overall process efficiency.

In building block 2, the EPA CO2 rate setting calculation assumes that existing combined cycle gas turbines (CCGT) could average up to a 70% utilization rate per year starting 2020. EPA derived at this assumption by arbitrarily using a $30/ton $CO_2$ price as a "reasonable cost" that consumers should pay to substitute natural gas for lower cost coal generated electricity and calculated the CCGT resulting capacity factor from applying this penalty. This building block amounts to converting grid operations from economic to forced environmental dispatching. While existing CCGT plants subject to the CPP technically may be capable of operating at such high utilization rates, it remains substantially higher than historic averages and lacks any technical or additional economic support why I would be considered a "best system of emission reduction."

EPA selected state CO2 rates that assume renewable energy growth of 86% more renewable generation, nationally from 2020 to 2030. However, EPA's assumptions far exceed its own modeling results. In its state $CO_2$ emission rate calculation, the EPA assumes that non-hydro renewable generation will increase to 525 TWh by 2030. In contrast, the agency's own modeling results, which present the lowest cost strategy to comply with the proposed rule, show only 356 TWh of non-hydro renewable generation by that time.

States would achieve demand-side energy efficiency (EE) savings that would improve 250% nationally from 2020 to 2030: EPA's assumption of 1.5% annual incremental savings nationwide results in energy efficiency gains outpacing electricity demand growth, resulting in declining retail electricity sales between 2020 and 2030. EPA is effectively predicting a negative electricity demand growth during the compliance period (2020-2030) which is inconsistent with the U.S. Department of Energy, the Energy Information Administration, and other respected electricity demand forecasts.

## EVA Modeling of EPA Building Blocks

Based upon EVA's extensive market knowledge, experience with the energy sector, the following assumptions for the four building blocks were made to more accurately represent the U.S. energy sector for EVA's detailed analysis of the proposed Clean Power Plan:

- **Coal Plant Heat Rate Improvements:** EVA uses an algorithm for estimating heat rate improvements with a capital investment based upon current plant heat rate, age, coal rank, existing heat rate efficiency and emission controls. This study found that utilities already practice best operational practices so no incremental heat rate improvement was possible without making additional capital investment in process improvements. Overall, these investments could improve potentially performance by an average 1.1% across the entire coal-fired generating fleet. However, there is a significant risk that this investment could also potentially trigger new source review and much higher capital investment in retrofitting additional environmental controls in several cases.

- **CCGT Capacity Factor:** EVA determined from its power market analysis that CCGTs will not economically dispatch at an average 70% utilization rate in the power markets. EVA allowed its power dispatch model to determine how each existing CCGT plant would operate on an hourly basis based on market economics.

- **Renewable Generation Growth:** EVA utilized an internally developed state-by-state forecast of renewable capacity deployment that accounts for each state's Renewable Portfolio Standard (RPS), considers individual state's economically reasonable renewable resource limitations and the cost effectiveness of each type of renewable capacity source.

- **Demand Side Energy Efficiency:** EVA relied on the Electric Power Research Institute's (EPRI) study "U.S. Energy Efficiency Potential through 2035" to derive an energy efficiency forecast that accounts for the adoption of energy-efficient technologies while taking into consideration individual technical, economic and market constraints for each state. A higher energy efficiency adoption rate was applied to states that possess a greater energy efficiency score according to the American Council for an Energy-Efficient Economy. The resulting state-specific energy efficiency savings were applied to a proprietary electric power demand forecast.

## 2. Purpose of this Study

The Environmental Protection Agency's (EPA) Clean Power Plan (CPP) proposes to regulate $CO_2$ emissions from 3,104 US fossil-fired electric power generating units under the Clean Air Act.[1] The purpose of this study is to provide an independent evaluation of EPA's proposal and its impacts on the US energy markets and future power industry $CO_2$ emission. In detail, this study focuses on the following topics:

- Calculate state $CO_2$ penalties created to comply with EPA's proposed mass-based $CO_2$ emission limitations.
- Model power industry compliance strategies and their effect on electric power generation mix.
- Quantify the changes in electric fossil fuel demand and their impact on delivered fuel prices.
- Assess the effect of carbon penalties and fossil fuel market changes on regional wholesale power prices.
- Identify reasons for any major differences between EVA and EPA power model results.

## 3. Methodology to Analyze EPA's Clean Power Plan

For the purpose of this report, EVA prepared a forecast of future U.S. power and energy markets for the period 2013-2030 under two scenarios:

A. **Base Case:** Forecast of U.S. power markets using EVA's realistic energy market assumptions without any federal carbon emission regulation.
B. **Clean Power Plan (CPP) Case:** Forecast of U.S. power markets using EVAs realistic energy market assumptions set to meet EPA's state mass-based $CO_2$ emission targets.

In this study, EVA utilizes the commercially-available AuroraXMP (Aurora) electric power market forecasting tool. Aurora is an hourly economic dispatch model that calculates the lowest cost resource mix for each hour to simulate the operations of each power market in the continental U.S and builds the most economic new resources to backfill for retirements and meet future load growth. Aurora further applies EVA's natural gas and regional coal supply curves to calculate annual long-term equilibrium fossil fuel prices as well as annual long-term transportation costs utilizing EVA's natural gas basis differential and unit specific coal transportation forecasts for the years 2013 through 2040.

[1] *Federal Register Vol. 79, No. 117* (June 18, 2014), pg. 34829 -34958

For this study, the model calculates the minimum state specific annual CO2 penalty that would be applied to its affected fossil fuel capacity that would change the regional economic dispatch order to reduce annual emissions to comply with a state CO2 emission cap. This value is equivalent to the equilibrium CO2 emission allowance value in a future state cap & trade program. Differential CO2 penalties between states can and will change net sub-regional power flows within the transmission grid.

Given the complexities for states to implement a $CO_2$ rate-based limit program, this study evaluates the much easier to implement mass-based limit option that states are more likely to pursue under the EPA proposal. It is assumed that states will be able to develop, pass required legislation (to expand needed permit authorization), adopt and implement required compliance plans within the tight compliance schedule proposed by the EPA. In reality, this will clearly pose a challenge for most states. It is further assumed that the EPA will approve a cap-and-trade $CO_2$ trading program that meets the respective state's emission cap contained in the CPP proposal. States are also permitted to develop multiple state programs that would allow some further optimization across larger populations. However, this option was not modeled as it is uncertain which states may join together or may join existing cap-and-trade programs like RGGI and AB 32.

Additionally, it is assumed that affected sources will be able to plan, permit, finance and implement their compliance plans by 2020. This tight schedule will be a challenge as it takes approximately 5 to 8 years to plan, permit, finance, build, and operate new generating fossil fuel capacity and 5-15 years for new transmission lines. Natural gas pipelines are also assumed to be able to expand their capacity to handle the increased natural gas demand from power stations due to the CPP. In reality, this could propose a challenge as it takes 3 to 5 years to plan acquire right of way land rights, permit, finance, and build new pipeline capacity.

Finally, EVA already incorporates economically achievable energy efficiency measures into its "no CPP" base case. Therefore it is assumed that there will be no significant difference in electricity demand that is attributable to EPA's proposed Clean Power Plan.

## EPA's Clean Power Plan Proposal

Using its authority granted by Section 111(d) of the Clean Air Act, the EPA published on June 18, 2014, a proposed rule to regulate $CO_2$ emissions from existing power plants. The proposed rule, titled the Clean Power Plan (CPP) claims to reduce CO2 emissions of the entire US power sector by 30% from 2005 levels. [2]

The proposal applies to 3,104 qualifying fossil fuel electric generating units (EGUs), equal to 702,381 MW of nameplate capacity.[3] In general, affected units have to fulfill all of the following four requirements:

[2] *Federal Register Vol. 79, No. 117* (June 18, 2014), pg. 34829 -34958
[3] *EPA CPP TSD – 2012 Unit-Level Data Using EGrid – Methodology,*(EPA, June 2014). Generation, Emissions, Capacity data used in EPA's State Goal Computation TSD

- Any fossil fuel-fired EGU that was in operation or had commenced construction as of January 8, 2014
- Any EGUs that combust fossil fuel for more than 10% of their total annual heat input
- Any EGU that is capable of combusting at least 250 million Btu per hour
- Any EGU that sells the greater of 219,000 MWh per year and one-third of its potential electrical output to a utility distribution system

These qualification criteria effectively exempt 17,472 existing EGUs accounting for 612,112 MW of generating capacity from the proposed CPP.

The proposed rule requires states to develop implementation plans that meet EPA's proposed state-specific $CO_2$ emission rate limitations and are enforceable. The EPA expects to finalize the rule by June 2015. State Implementation Plans (SIPs) are due one year after the finalization of the rule, i.e. June 30, 2016. States can apply for a one-year extension (June 30, 2017) if necessary information is submitted. States that plan on participating in multi-state programs are awarded a 2-year extension, i.e. until June 30, 2018. Additionally, states are given the option to develop either a rate-based or a mass-based limitation approach. States are highly likely to adopt the mass-based alternative, as it is far easier and less resource intensive to implement and enforce. This study assumes that all states adopt a mass-based limitation approach.

EPA developed the state-specific $CO_2$ emission rate limitations by applying four building blocks that it considers as "Best System of Emission Reduction" (BSER) under section 111(d) of the Clean Power Plan. The following section reviews EPA's and EVA's assumptions regarding the four building blocks and highlights the differences.

### A. Coal Plant Heat Rate Improvements

In building block 1 of the CPP, EPA assumed that the operating coal-fired fleet can achieve an average heat rate improvement of 6% at an average cost of $100/kW in 2020. EPA used this assumption to reduce the allowable emissions of $CO_2$ by 6% of the 2012 emission rate for all of the coal units in each state.[4]

EPA's approach to determining emission rate reductions for heat rate improvements at coal units consisted of 2 components. First, EPA performed a statistical analysis of the efficiency of existing coal units and determined that the variation in efficiency showed that the heat rate of the entire fleet could be improved by an average of 4% simply by adopting "best practices" at no additional cost. Second, EPA relied upon a 2009 engineering study to conclude that an additional average heat rate improvement of 2% for the entire fleet was achievable through equipment upgrades at a cost of $100/kW. EPA added together the average efficiency improvements from adopting "best practices" and from equipment upgrades to conclude that the entire fleet of existing coal units could economically increase efficiency by 6% at a cost of $100/kW. EPA did not examine if the capital improvements would trigger new source review and require additional retrofitted environmental control measures.

[4] *GHG Abatement Measures* (EPA June 2014) (EPA-HQ-OAR-2013-0602), Chapter 2.

To calculate a more realistic coal plant heat rate improvement that can be achieved as a compliance strategy for CPP, EVA constructed the following methodology for its analysis of the CPP. First, utilities already incorporate best operational practices to optimize their existing performance. EPA's methodology is flawed by not accounting for differences in boiler design, age, fuel quality and cooling water systems that have significant effects on process efficiency and are outside operational practices. For each coal-fired unit affected by EPA's CPP, EVA created a matrix consisting of the age of the coal unit in 2020, environmental controls installed, rank of coal consumed, and its existing heat rate performance curve. Using the parameters from the matrix, a custom unit-specific calculation is performed that estimates the potential heat rate improvement ranging from 0% to 8%. The invested capital will also vary based on the relative improvement in heat rates.

For example, a 50-year old plant consuming bituminous coal operating with an average annual heat rate of 12,000 Btu/kWh with no scrubber could achieve a heat rate improvement of 8% by investing a capital of $150/kW. (This analysis does not account for any heat rate impairments resulting from installation of environmental control units.)

Alternatively, if a 40-year old coal-fired unit burns bituminous coal and operates at an average annual heat rate of 10,250 Btu/kWh with a wet scrubber, EVA assumes this unit could a achieve a heat rate improvement of 1% by investing $20/kW.

Using this analysis, EVA estimates a fleet-wide average heat rate improvement of 1.1%, in contrast to EPA's fleet-wide 6% reduction.

### B. CCGT Capacity Factor

The EPA states $CO_2$ rate limits are calculated using a 70% capacity factor for existing CCGT plants starting in 2020.[5] EVA allowed its power dispatch model to determine how each existing CCGT plant would operate hourly based on market economics rather than setting a fixed capacity factor performance.

### C. State Renewable Outlook

Another measure the EPA used to reduce $CO_2$ emissions from existing power plants is expansion of new non-hydro renewable energy generation such as solar, wind, biomass and geothermal. When projecting the future construction of new renewable energy sources, the EPA relied on existing Renewable Portfolio Standards (RPS) to estimate regional growth rates and calculate renewable generation during the modeling time frame. [6]

The EPA used a renewable generation outlook to construct its state-by-state $CO_2$ emission rate limits that was greater than the one it applied to its power modeling effort, which was used as part of its regulatory impact analysis. The EPA's calculations include qualifying non-hydro renewable generation growing from 213 TWh in 2012 to 281 TWh by 2020, reaching 523 TWh by 2030.[7] Interestingly, these projections are considerably higher than EPA's own modeling

[5] *GHG Abatement Measures* (EPA June 2014) (EPA-HQ-OAR-2013-0602), Chapter 3.
[6] *GHG Abatement Measures* (EPA June 2014) (EPA-HQ-OAR-2013-0602), Chapter 4.
[7] *State Goal Computation TSD* (EPA June 2014) (EPA-HQ-OAR-2013-0602).

results, where in 2020 and 2030 non-hydro renewable energy generation was only 323 TWh and 356 TWh, respectively. [8]

By contrast, EVA utilized an internally developed state-by-state forecast of renewable capacity deployment that takes into account each state's renewable project development activity (type, cost, development status, announced online date), output performance(by type), existing incentive programs (e.g. RPS), state renewable resources/limitations (biomass, geothermal, solar, wind) and production cost for each renewable technology option. Renewable development costs remain above conventional generation and therefore heavily dependent upon continued governmental program incentives. EVA's modeled non-hydro renewable energy generation values are very similar to the EPA's modeling inputs, i.e. 301 TWh in 2020 and 360 TWh in 2030.

### D. State Demand-Side Energy Efficiency Savings

According to the EPA, improved demand-side energy efficiency will effectively lower electricity generation from existing power plants and subsequently lower $CO_2$ emissions. The EPA assumed a 1.5% annual incremental savings nationwide for the modeling horizon, which results in energy efficiency gains outpacing electricity demand growth, resulting in a net decline in retail electricity sales from 2020 through 2030.

The EPA energy efficiency savings for the lower 48 states in 2020 and 2030 are estimated to be 119 TWh and 469 TWh, respectively.[9] The EPA applies these energy efficiency savings to the U.S. Energy Information Administration's (EIA) Annual Energy Outlook (AEO) 2013 regional electricity demand outlook, which ultimately results in annual EE savings outpacing annual incremental electricity demand growth, causing a decline in total U.S. retail sales during the modeling period.

For its analysis, EVA relied on the EPRI study "U.S. Energy Efficiency Potential through 2035" to derive an energy efficiency forecast that accounts for the adoption of energy-efficient technologies while taking into consideration individual technical, economic, and market constraints for each state. [10] States were assumed to implement all reasonable economic potential measures in the EPRI study. A higher energy efficiency adoption rate was applied to states that possess a greater energy efficiency score according to the American Council for an Energy-Efficient Economy. [11]

For the lower 48 states, EVA assumes 179 TWh and 391 TWh in annual energy efficiency savings in 2020 and 2030, respectively. These resulting state-specific energy efficiency savings were applied to a proprietary electric power demand forecast. EVA's energy efficiency assumption is based on the likelihood that these investments will be made independently of the EPA's CPP proposal.

[8] *Regulatory Impact Analysis for the Proposed Carbon Pollution Guidelines for Existing Power Plants and Emission Standards for Modified and Reconstructed Power Plants* (EPA June 2014) Table 3-11 pg. 3-27

[9] EE savings estimates calculated using EPA's methodology, EE savings %, BAU sales estimates. Source: *GHG Abatement Measures* (EPA June 2014) (EPA-HQ-OAR-2013-0602) Chapter 5

[10] Source: http://www.epri.com/abstracts/Pages/ProductAbstract.aspx?ProductId=000000000001025477

[11] Source: http://aceee.org/research-report/e13k

## E. State – Specific Mass-based $CO_2$ Emission Limits

Utilizing the four building blocks previously described, Exhibit 3.1 shows the formula used by the EPA to calculate each state's interim emission rate goal (average 2020-2029) and final emission rate goal (2030 and beyond).

**Exhibit 3.1: Formula Used to Calculate EPA State Emission Rates Targets[12]:**

$$EPA\ State\ Emission\ Rate = \frac{(Coal_{Gen} * Coal_{Emission\ Rate}) + OG_{Gen} * OG_{\ Emission\ Rate}) + NGCC_{Gen} * NGCC_{Enission\ Rate}) + CT/GT_{Emissions}}{Coal_{Gen} + OG_{Gen} + NGCC_{Gen} + CT/GT_{Gen} + Nuclear_{Gen\ (uc+ar)} + RE_{Gen} + EE_{Gen}}$$

As suggested in EPA's documentation, EVA used EPA's emission rate formula to convert a state's annual emission rate-based goal to an annual emission mass-based goal ($CO_2$ Tonnage Cap).[13] The resulting formula is shown in Exhibit 3.2.

**Exhibit 3.2**: **Formula Used By EVA to Calculate State Emission Cap Limits:**

$$State\ Emission\ Cap\ (tons) = EPA\ State\ ER * (Coal_{Gen} + OG_{Gen} + NGCC_{Gen} + CT/GT_{Gen} + Nuclear_{Gen\ (uc+ar)} + RE_{Gen} + EE_{Gen})$$

EVA used EPA's 2012 generation estimates as published in its "State Goal Computation" TSD to calculate each state's individual state emission cap in tons. Although the state emission rate limit changes between the interim and final limitation, EPA used the same mass based cap in its calculations. The reduction in state rate limits between the interim and final period is attributable to 10 years of growth (2020-2030) growth in both state renewable generation and energy efficiency savings.

Exhibit 3.3 shows the state-specific $CO_2$ tonnage cap (in thousand short tons) used in EVA's study of the CPP.

[12] *State Goal Computation TSD* (EPA June 2014) (EPA-HQ-OAR-2013-0602). OG = Oil-Gas Steam, NGCC = Natural Gas Combined Cycle, GT/CT – Gas Turbine, Combustion Turbine, uc+ar = under construction + at risk

[13] *Projecting EGU CO2 Emission Performance in State Plans* (EPA June 2014) Chapter 3.

**Exhibit 3.3: State Emission Caps Used in EVA Study (1,000 tons/year):**

| State | Emission Cap | State | Emission Cap |
|---|---|---|---|
| Alabama | 66,159 | Nebraska | 24,376 |
| Arizona | 23,473 | Nevada | 12,529 |
| Arkansas | 25,763 | New Hampshire | 3,642 |
| California | 48,626 | New Jersey | 11,350 |
| Colorado | 33,636 | New Mexico | 13,963 |
| Connecticut | 6,380 | New York | 29,316 |
| Delaware | 3,880 | North Carolina | 51,180 |
| Florida | 89,610 | North Dakota | 31,369 |
| Georgia | 50,964 | Ohio | 94,737 |
| Idaho | 704 | Oklahoma | 40,060 |
| Illinois | 81,860 | Oregon | 6,048 |
| Indiana | 93,251 | Pennsylvania | 105,471 |
| Iowa | 32,110 | Rhode Island | 3,736 |
| Kansas | 32,360 | South Carolina | 30,353 |
| Kentucky | 86,435 | South Dakota | 2,147 |
| Louisiana | 34,917 | Tennessee | 36,785 |
| Maine | 1,743 | Texas | 185,472 |
| Maryland | 18,579 | Utah | 25,639 |
| Massachusetts | 11,628 | Virginia | 26,974 |
| Michigan | 58,024 | Washington | 4,289 |
| Minnesota | 19,051 | West Virginia | 68,005 |
| Mississippi | 21,200 | Wisconsin | 34,450 |
| Missouri | 69,382 | Wyoming | 47,163 |
| Montana | 16,873 | | |

These $CO_2$ emission caps have been held constant throughout the compliance period (2020-2030). As EPA's calculated state-specific emission rate goal (lbs/MWh) decreases from 2020 to 2030, EPA's estimated generation from non-hydro renewables and avoided generation from energy efficiency measures increases over the same time period. Using the formula presented in Exhibit 3.2, this leads to a constant $CO_2$ emission cap for the compliance period (2020-2030).

## 4. Major Study Findings

The following section summarizes the major findings of the study prepared by EVA. The major findings focus primarily on the impacts and compliance cost of the proposed Clean Power Plan (CPP) on for the US power sector.

### A. Electricity Demand Is Growing – Not Shrinking

US demand for electricity is expected to grow slowly throughout the modeled time frame (2013-2030) as US population and economic activity continue to grow. EVA's base case incorporates reasonable achievable potential savings from various energy efficiency measures through continued investments. No incremental change is expected due to the proposed regulation. As shown in Exhibit 4.1, EVA's electricity demand outlook closely matches EPA's business-as-usual electricity demand forecast. However, in EPA's analysis of the CPP proposal, electricity demand is expected to contract by 0.21% per year between 2020 and 2030 due to increased electricity savings from energy efficiency measures. A comparison of annual average growth rates in electricity demand is shown in Exhibit 4.2. This declining electricity demand assumption results in significantly reducing the projected industry and fuel market impact and is highly unrealistic.

**Exhibit 4.1: Comparison of Total Generation:**

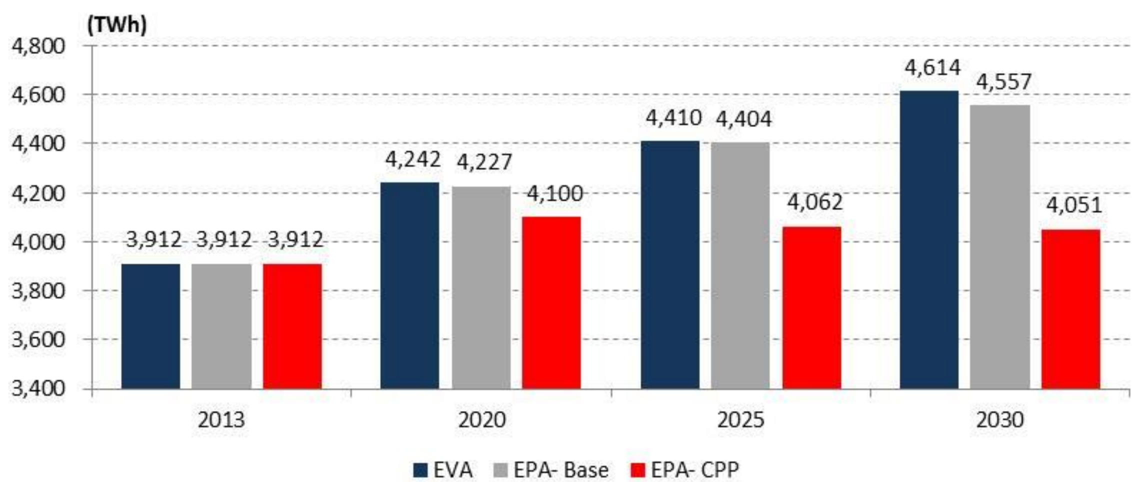



**Exhibit 4.2: Comparison of Average Annual Growth Rates:**

| | CAGR '13-'30 | CAGR '20-'30 |
|---|---|---|
| EVA | 0.98% | 0.85% |
| EPA- Base | 0.90% | 0.75% |
| EPA- CPP | 0.21% | -0.12% |

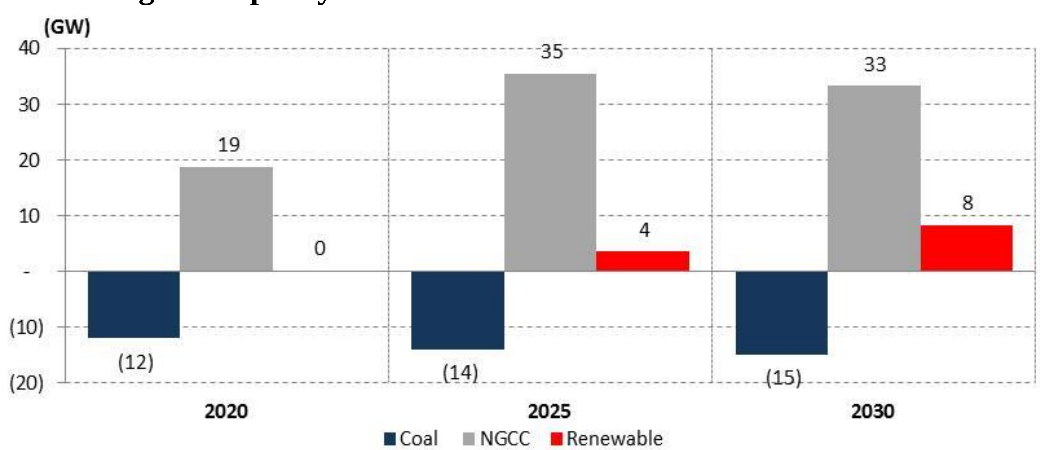
## B. New Natural Gas Combined-Cycle and Non-Hydro Renewables Replace Retiring Coal Capacity

According to EVA's study results, the US power sector will need to add between 80 and 100 GW of power capacity by 2030 to meet the growing electricity demand alone. Without any carbon regulation, the power industry would retire by 2020 about 49 GW of coal-fired generating capacity due to other recent EPA regulations, such as MATS and Cooling Water Intakes (316(b)), as shown in Exhibit 4.3. With the CPP in place as proposed, the power industry is expected to accelerate retirements of an additional 12 GW of coal-fired and 7 GW of oil/gas steam capacity by 2020. In both base case and CPP compliance case, most new capacity additions will be from natural gas combined cycle (NGCC) and non-hydro renewable sources, as shown in Exhibit 4.4. In the base case, EVA estimates that 100 GW of NGCC capacity and 45 GW of non-hydro renewable capacity will be added by 2030. The implementation of the CPP would increase these numbers to 133 GW and 53 GW, respectively.

**Exhibit 4.3: Detailed Capacity Portfolio Base Case vs. CPP Case:**

| Year | Coal | NGCC | Renewable | Other | Total |
|---|---|---|---|---|---|
| | | | **Base Case** | | |
| **2013** | 307 | 221 | 76 | 429 | 1,032 |
| **2020** | 258 | 280 | 105 | 438 | 1,081 |
| **2025** | 253 | 286 | 113 | 449 | 1,102 |
| **2030** | 245 | 322 | 121 | 425 | 1,113 |
| | | | **CPP Compliance Case** | | |
| **2020** | 246 | 299 | 105 | 430 | 1,079 |
| **2025** | 239 | 321 | 117 | 436 | 1,113 |
| **2030** | 231 | 355 | 130 | 418 | 1,133 |
| | | | **Difference Due to Clean Power Plan** | | |
| **2020** | (12) | 19 | 0 | (8) | (1) |
| **2025** | (14) | 35 | 4 | (14) | 11 |
| **2030** | (15) | 33 | 8 | (7) | 20 |

**Exhibit 4.4: Change in Capacity CPP Case minus Base Case:**



In conclusion, the implementation of EPA's Clean Power Plan as proposed would require a $53 billion higher generating capacity investment by 2030 in order to replace accelerated coal and oil/gas steam unit retirements.

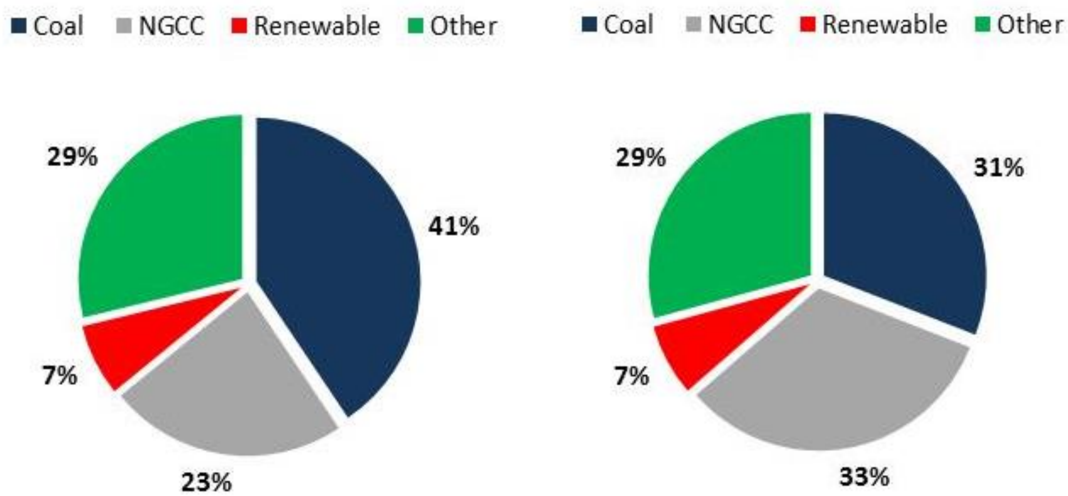
## C. Generation Shifts towards More NGCC and Less Coal

The Clean Power Plan as proposed will reduce US coal generation by about 25 percent or 410-450 TWh (Exhibit 4.5). Almost all of the lost coal generation will be replaced by NGCC generation. Non-hydro renewable generation will see only slight increases compared to the base case, as their much higher production costs and state resource limitations make them less competitive versus new gas combined cycle alternatives. In 2020, roughly 160 TWh of the displaced coal generation will come from existing NGCC units also regulated under the CPP. By 2030, this share shrinks to 80 TWh. Most of the displaced coal generation will then come from new NGCC capacity, which is exempt from the CPP $CO_2$ limitations. Under the CPP case, NGCC generation will displace coal generation as the primary source of electricity in 2020, as shown in Exhibit 4.6.

**Exhibit 4.5: Detailed Generation Mix Base Case vs. CPP Case**

| Year | Coal | NGCC | Renewable | Other | Total |
|---|---|---|---|---|---|
| | | | **Base Case** | | |
| **2013** | 1,468 | 1,009 | 231 | 1,203 | 3,912 |
| **2020** | 1,722 | 997 | 301 | 1,222 | 4,242 |
| **2025** | 1,769 | 1,060 | 321 | 1,259 | 4,410 |
| **2030** | 1,749 | 1,318 | 340 | 1,207 | 4,614 |
| | | | **CPP Compliance Case** | | |
| **2020** | 1,301 | 1,375 | 301 | 1,230 | 4,207 |
| **2025** | 1,321 | 1,494 | 329 | 1,232 | 4,376 |
| **2030** | 1,334 | 1,719 | 359 | 1,173 | 4,585 |
| | | | **Difference (%) Due to Clean Power Plan** | | |
| **2020** | -24.5% | 37.9% | 0.1% | 0.7% | -0.8% |
| **2025** | -25.3% | 40.9% | 2.5% | -2.2% | -0.8% |
| **2030** | -23.7% | 30.5% | 5.5% | -2.8% | -0.6% |

**Exhibit 4.6: Changes in Generation Mix Base Case vs. CPP Case:**




The EPA Clean Power Plan will most likely reduce US coal generation by 25 percent. Most of these losses will be replaced by new NGCC generation that is exempt from this regulation. Some lost coal generation will be replaced by increased generation from existing NGCC units. Finally, non-hydro renewable generation will see only minimal increases, as resource limitations and production costs make natural gas the preferred alternative.

## D. Higher Natural Gas Demand from Power Sector Drives Up Gas Prices

The higher natural gas demand from the power sector due to the forced environmental dispatch under the CPP creates more demand for natural gas during the winter heating season. Exhibit 4.9 displays the increase in the power sector's natural gas demand due to the CPP. This will increase the risk of pipeline delivery bottlenecks and potential delivery disruptions in regions already highly constrained like New England. The increase in demand will require more pipeline and production capacity to be built, which will take a significant amount of time to plan, permit, finance, and build. Until the infrastructure is sufficient in capacity, there will be greater risk of increased price differentials during high demand winter heating season periods, driving up power prices well above normal levels. Higher demand in natural gas will also require more well-drilling activities and higher commodity prices in order to support the incremental production costs. Exhibit 4.10 shows the increase in Henry Hub natural gas prices due to the Clean Power Plan. Ultimately, these price impacts in wholesale power and natural gas will be passed onto power and non-power consumers in the industrial, commercial, and residential sectors.

**Exhibit 4.9: Natural Gas Demand Increases in the Power Sector under the CPP**

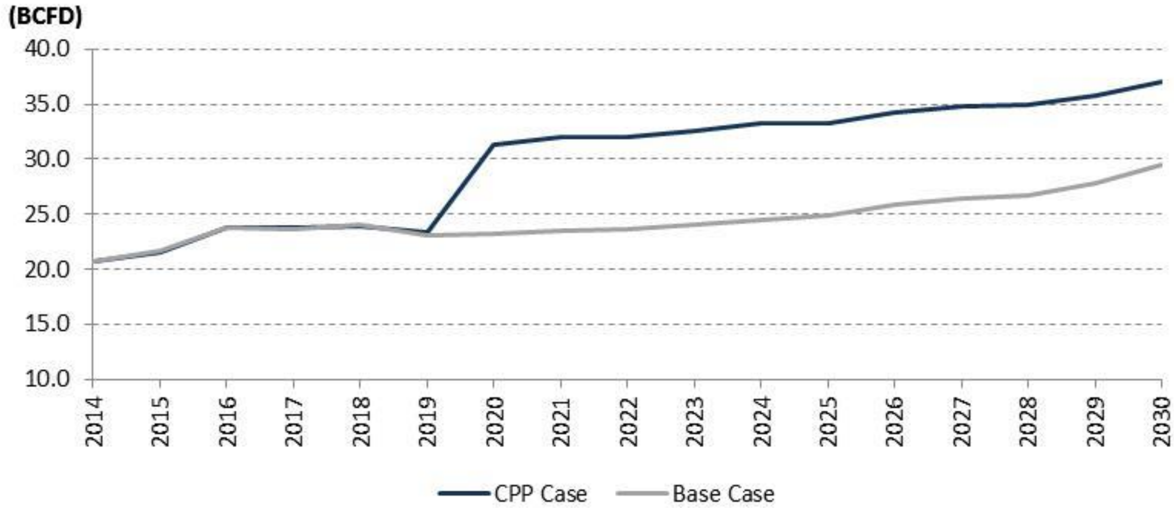
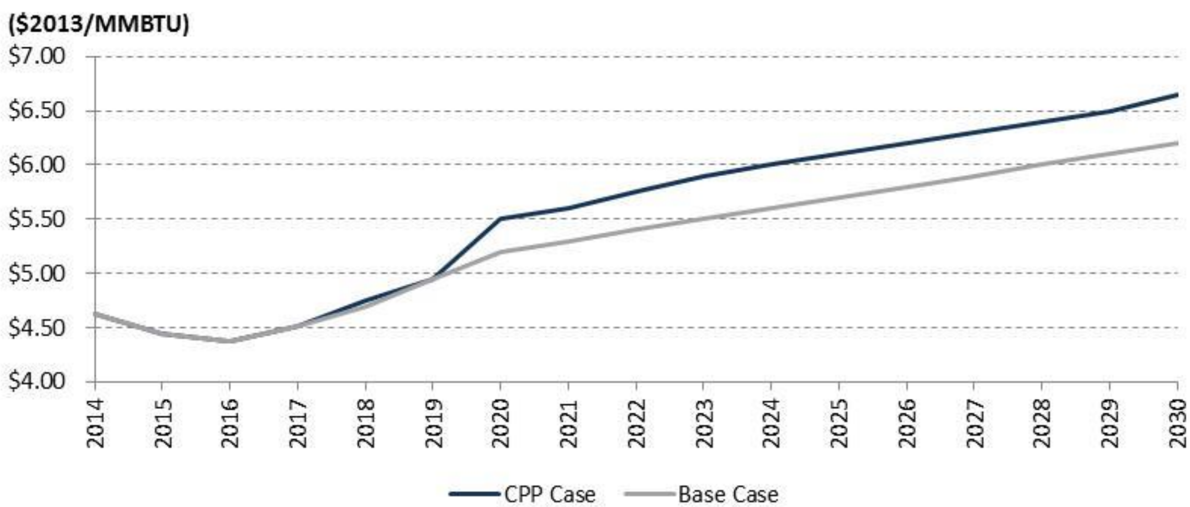


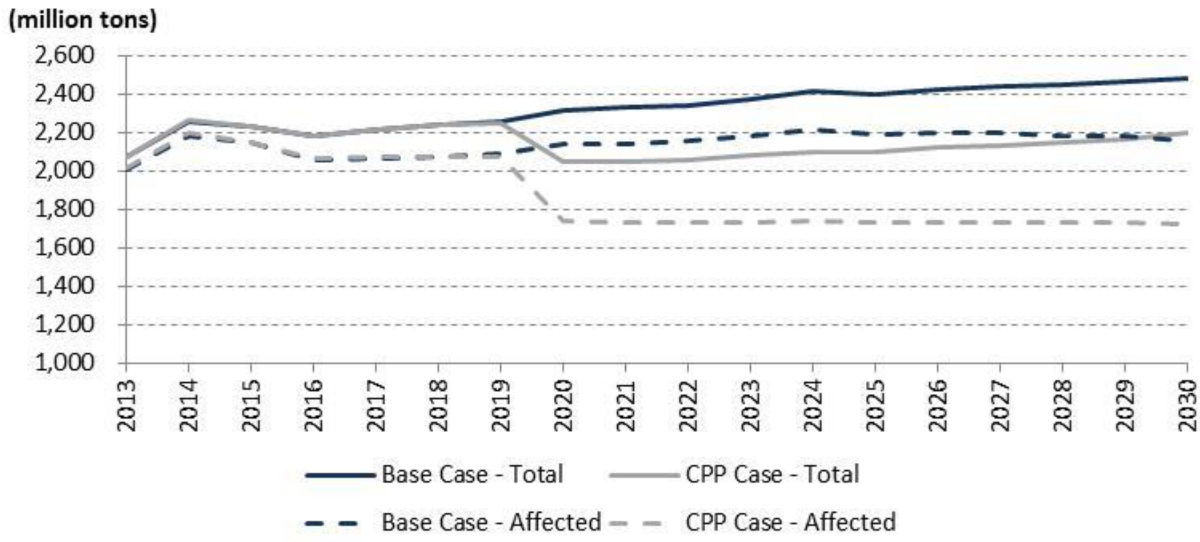

**Exhibit 4.10: Natural Gas Henry Hub Price Increases under the CPP:**




## E. US Power $CO_2$ Emissions Decline by 270-300 Million Tons/Year Under CPP

As shown in Exhibit 4.11, the total power industry's $CO_2$ emissions will decline by 270 to 300 million tons per year under the CPP compliance case scenario compared to the base case. In particular, $CO_2$ emissions from CPP affected existing power sources will decline by 400 to 450 million tons per year. However, these reductions are partially offset by emissions from new CPP exempt power sources (e.g. new NGCC, CT), which $CO_2$ emissions are expected to increase by 130 to 160 million tons per year. Overall, under a mass-based limitation approach, the total US power sector emissions will decrease by 21.2% in 2030 compared to 2005 levels.

**Exhibit 4.11: Power Sector $CO_2$ Emissions by Source:**




## F. Carbon Penalties Vary Widely by State

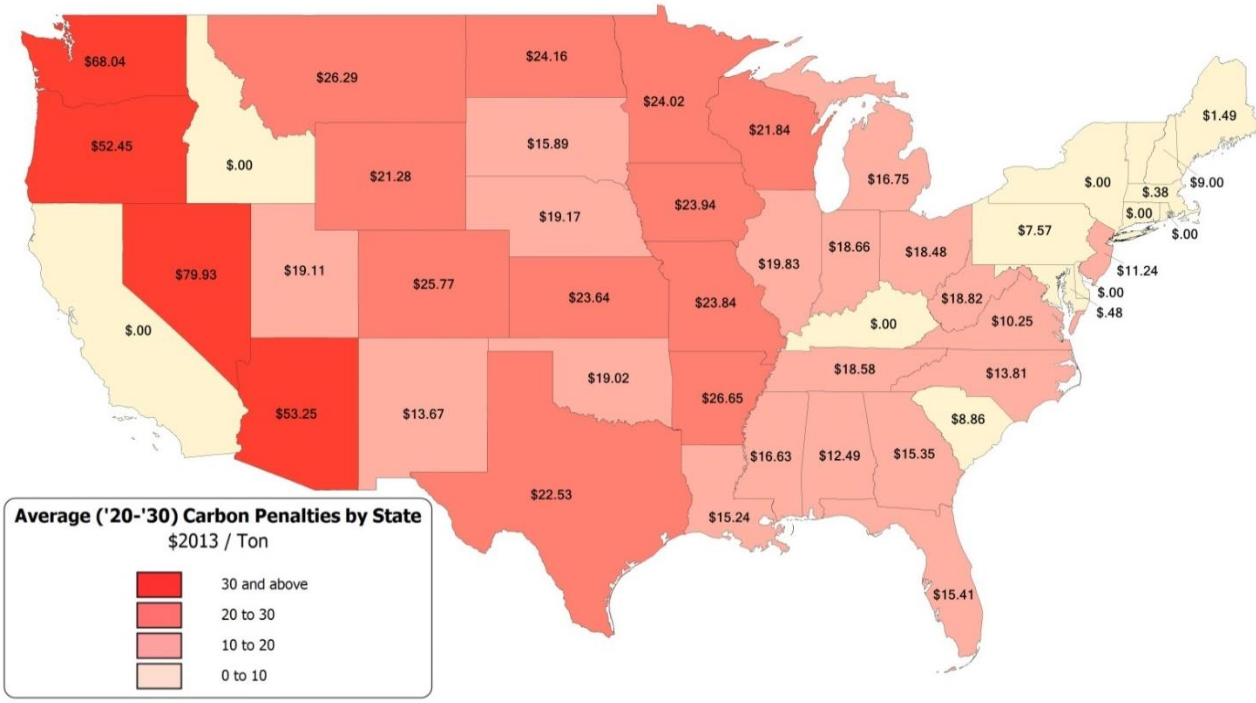
A carbon penalty is an indirect market mechanism needed to comply with the Clean Power Plan as proposed. The value of this carbon penalty depends on the state and the $CO_2$ emission rate of the particular unit. A carbon penalty is necessary to make coal generation less economical than lower $CO_2$ emitting natural gas generation, increase imports/ reduce exports of power, and/or increase non-hydro renewable generation in order to meet the state $CO_2$ tonnage limitation.

The carbon penalties for the nine RGGI states (CT, DE, MA, MD, ME, NH, NY, RI, VT) are comparatively low since RGGI program requirements are more stringent than EPA's proposed CPP (RGGI includes all power sector and some industrial sector $CO_2$ emissions in its cap-and-trade program).

California also has no incremental carbon penalty because of the much stricter program requirements of California's AB 32 cap-and-trade program. AB 32 includes all in-state carbon emitting sources (e.g. cars, gas heating, industrial, new sources) and has a declining emissions cap. Due to high forecasted AB 32 prices in California, the carbon penalties in the western states are generally much higher. A high AB 32 price makes it very economical for California surrounding states to export power to said state. However, in order to comply with their respective $CO_2$ mass limitations under the CPP, surrounding states' carbon penalties levelize at rates similar to California's AB32 prices therefore limit said export. Therefore, California shifts towards less power imports and more in-state generation to meet increasing power demands.

Exhibit 4.12 shows the average carbon penalties by state.

**Exhibit 4.12: Average ('20-'30) Carbon Penalties by State ($2013/Ton):**




## G. The Clean Power Plan Creates Potential Grid Reliability Issues

- ***The CPP provides incentives for more non-hydro renewable generation.***
  Increased generation from variable resources (e.g. wind, solar) will require greater amounts of ancillary services and greater investments in transmission lines to access wind-rich (but remote) areas. These costs have not been captured in EPA's or this analysis of the CPP, but will be passed onto the individual ratepayers. It is also highly unlikely that developers will be able to plan, permit, finance, and build projected non-hydro renewable capacity in time for compliance by 2020.

- ***Actual effects of energy efficiency projected by the CPP are uncertain.***
  In its CPP proposal, the EPA projects future energy efficiency measures to reduce electricity consumption and consumer electricity bills by adopting aggressive program assumptions. However, the more likely outcome (as projected in this study) will be increased demand in power and therefore the need for new generating capacity. It is doubtful that US regulators and power suppliers will be able to plan, permit, finance, and build the needed new generating capacity in time for compliance by 2020.

- ***The CPP limits coal unit output in order to meet the emission limits.***
  These mass-based $CO_2$ emission limitations are much stricter than any previous federal emission reduction program implemented by the EPA (e.g. Acid Rain, CAIR). States will need to reduce their existing coal unit generation output to achieve CPP $CO_2$ limitations. In some cases the combination of compliance investments needed to meet other environmental requirements and the outlook for future limited unit utilization will force some power suppliers to retire their higher cost coal units earlier (as early as 2016 in

EPA's analysis). Accelerated coal unit retirements may require additional investments in new generating capacity to assure the availability of sufficient reserve capacity. This unexpected replacement capacity could take 5-8 years to bring online if projects are not already in the development pipeline.

- ***The CPP adversely impacts power flows between states.***
  Under the CPP as proposed, limiting state power export sales is a potential compliance strategy. It is uncertain how companies that depend upon imported power from out-of-state will be able to replace lost (but much needed) generation by 2020. If states fall short of EPA expected non-hydro renewable generation and energy efficiency savings targets, states will likely be forced to further limit generation from existing units and invest in new generating capacity.

- ***The Implementation schedule of the CPP is extremely short.***
  In order to comply with the Clean Power Plan starting in 2020, most states will need to adopt new legislation to authorize the development of a state cap-and-trade program and/or state authority to limit unit-specific power output. It is apparent that EPA did not provide states with enough time to pass required authorizing legislation, develop state compliance plans, collect/analyze/react to public comments to finalize state compliance plan and to receive final plan approval by the EPA. Additionally, US power sources must plan, permit, finance, contract and build large infrastructure (i.e. pipelines, transmission lines, new generating capacity) in a short time period before the start of compliance in 2020.

## 5. Conclusion

EPA's proposed Clean Power Plan will have significant impacts on the US power industry and the consumers it serves beyond those already being incurred due to recent EPA regulations on the power sector. To meet its requirements, the industry must dramatically change its generation mix, shifting away from coal to natural gas. Consumers would need to invest an additional $53 billion (2013$) in new gas and renewable generation capacity to replace lost coal generation capacity. This large generation shift will create sizeable increases in natural gas demand that will increase natural gas prices not only for the electric utility industry, but also for the 15-17 TCF/year consumed by all other gas consumers (residential heating/cooking, commercial, non-power industrial). Outside the power industry, natural gas commodity prices would increase by $80 billion during the period 2020-2030. As coal demand shrinks, employment would also decrease.

Wholesale power prices would increase by $274 billion over the initial compliance period (2020-2030) to capture higher production costs and new carbon penalties. These price increases and energy impacts will not be evenly spread throughout the states. Higher energy prices (gas, power) could impact US economic growth in ways that were not evaluated in this study. In return for higher energy prices, the Clean Power Plan would reduce US power industry net-CO2 emissions by 270-300 million tons per year after accounting for the emissions from new unregulated power plants that will be built to replace electricity generation from power plants retired due to the CPP.