Energy Market Impacts of Recent Federal Regulations on the Electric Power Sector

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Executive Summary

The Environmental Protection Agency (EPA) has issued several new regulations on the electric power sector in recent years, the vast majority of which target power plant emissions under the authority of the Clean Air Act (CAA). These regulations include, but are not limited to: new National Ambient Air Quality Standards (NAAQS) for ozone and particulate matter; the Cross-State Air Pollution Rule (CSAPR) to address interstate transport of air pollution; Mercury and Air Toxics Standards (MATS) under CAA Section 112; and regional haze regulations intended to improve visibility in public parks. Most recently, in June 2014, under the authority of CAA section 111(d), the EPA proposed guidelines to cut carbon dioxide (CO_2) emissions from existing fossil-fueled power generating units in the electric power sector. The proposed rule is referred to as the Clean Power Plan (CPP), and the EPA believes it would achieve CO_2 emission reductions from the power sector of approximately 30% by 2030 versus 2005 levels. Each of these regulations has imposed new costs on the electric power sector, and, by extension, consumers.

A great deal of research has been put forward to assess the impact of the CPP on the U.S. economy. Most has focused on the incremental costs of the CPP relative to a particular baseline. The purpose of this study by Energy Ventures Analysis (EVA) is to better understand the cumulative impact the proposed CPP, recent air regulations and other market forces will have on both the U.S. economy as a whole and on average U.S. households. The study analyzes the increases in electricity and gas costs from 2012 (the base year of EPA's CPP proposal) to 2020, the first year of EPA's interim CO_2 targets.[1] The cost comparisons are presented in both nominal and real dollars. However, because income growth is being outpaced by inflation for many Americans (the lower earning half of U.S. households experienced a 25% decline in real income from 2001-2014[2]), the authors of this report believe that it is more appropriate to focus on the results in nominal terms.[3]

Cost Impacts

EVA's evaluation identified potential oversights in the EPA's assumptions and analyses across multiple regulations, the combination of which has resulted in the EPA underestimating the actual cost of compliance with these regulations and their impact on energy markets. Additionally, baseline electricity and natural gas prices are expected to rise over the next 10 years. EVA's study estimated the combined impact of these market factors, recent final regulations, and the proposed CPP and found:

- Annual power and gas costs for residential, commercial and industrial customers in America would be $284 billion higher ($173 billion in real terms[4]) in 2020 compared to 2012—a 60% (37%) increase.
    - Electricity cost increases represent $177 billion ($98 billion) and natural gas increases represent $107 billion ($75 billion) of the $284 billion ($173 billion) cost increase from 2012 to 2020.

- In 2020, annual residential power and gas costs would be $102 billion ($87 billion) higher and would continue to escalate in subsequent years.
- Average annual household gas and power bills would increase by $680 ($293) or 35% (15%) from 2012 to 2020.
    - Annual average electricity bills would increase approximately $340 ($102) or 27% (8%) from 2012 to 2020.
    - Annual average home gas heating bills would increase approximately $340 ($190) or 50% (28%) from 2012 to 2020.
- The cost of electricity and natural gas will be impacted in large part due to an almost 135% increase in the wholesale price of natural gas (100% in real dollars), from $2.82/mmbtu in 2012 to approximately $6.60/mmbtu ($5.63) in 2020. These increases are due to baseline market and policy impacts between 2012 and 2020 as well as significantly increased pressure on gas prices resulting from recent EPA regulations on the power sector and the proposed CPP.[5]
- On a percentage basis, the U.S. industrial sector would be affected most severely, as its total cost of electricity and natural gas would approach $200 billion ($170 billion) in 2020, a 92% (64%) increase from 2012.
    - Increased operational costs in the industrial sector are of particular concern for energy intensive industries in the U.S. such as aluminum, steel and chemicals manufacturing, which require low energy prices to compete.
    - Industrial power consumers would be expected to pass energy cost increases on to their customers, affecting the costs of goods purchased by American consumers over and above increased monthly utility bills.
- The five states that would bear the greatest increases in annual residential power bills are Texas, Mississippi, Pennsylvania, Maryland and Rhode Island. Families in these states would experience average electricity increases of more than $660 ($566) annually beginning in 2020 compared with 2012.
    - In order to comply with the combined impact of recent power sector regulations and the proposed CPP, these states would face the choice of significantly increasing gas generation and/or significantly increasing wind and solar generation. The reduced operation of coal-fueled generation would render the surviving coal-fired power plants less efficient, producing more CO_2 per megawatt hour (MWh) than if they operated at full output.
- With regard to gas bills, colder weather states in the Northeast and Upper Midwest that use the most natural gas per household would bear the greatest impacts.
- The states that would incur the largest total cost increases on a percentage basis are Texas, Mississippi, Louisiana and North Dakota, averaging more than 115% increase in annual electricity and natural gas bills from 2012 to 2020.

U.S. Electricity and Natural Gas Cost Increases (Nominal Dollars)	2012	2020 CO_2 Case	Increase ($)	Increase (%)
Avg. Annual Residential Customer's Electricity and Natural Gas Bill ($)	1,963	2,643	680	35%
Industrial Electricity Rate (¢/kWh)	6.7	10.5	3.8	56%
Total Cost of Electricity and Natural Gas for All Sectors ($ Billion)	470	754	284	60%

U.S. Electricity and Natural Gas Cost Increases (Real Dollars)	2012	2020 CO_2 Case	Increase ($)	Increase (%)
Avg. Annual Residential Customer's Electricity and Natural Gas Bill ($)	1,963	2,256	293	15%
Industrial Electricity Rate (¢/kWh)	6.7	8.9	2.2	33%
Total Cost of Electricity and Natural Gas for All Sectors ($ Billion)	470	644	174	37%

Figures in Constant 2012 Dollars

Regulatory, Technology and Market Assumptions

2012 Baseline

This study uses 2012 as the base year to match the EPA's base year for the CPP analysis for consistency of benchmarking system data, assumptions and cost impacts. There are several federal regulations from the EPA that are being implemented in 2012 and beyond that impact the future costs of energy for electricity and natural gas users. The 3 major ones are Mercury and Air Toxics Standards (MATS), Regional Haze and the newly proposed Clean Power Plan (CPP) to regulate CO_2 from existing power generation sources.

Mercury and Air Toxics Standards (MATS)

EPA published its final Mercury and Air Toxics Standard (MATS) for the electric power industry in February 2012. This standard sets strict emission rate limitations for fossil fired electric power plants for acid gases, heavy metals and mercury.

To comply with the final rule, many existing coal-fired power plants would need to invest in expensive post combustion controls by April 2015 or retire. While uncontrolled oil/gas-fired generating units will be able to meet the standards without major capital investments, most uncontrolled coal-fired units will be required to make such investments to continue operations. Most bituminous coal-fired boilers will be required to operate wet flue gas desulfurization (Wet Scrubber) systems to meet the mercury and acid gas limitations. Those facilities burning Powder River Basin coals may be able to comply by installing dry sorbent injection (DSI) retrofits in combination with an activated carbon injection (ACI) system. To limit heavy metal emissions from coal plants, most facilities will be required to invest in either electrostatic precipitator (ESP) upgrades or retrofits of new fabric filter systems.

All existing coal- and oil-fired electric utility units will be required to meet their respective emission targets starting April 2015, with possible extensions until April 2016 or in extraordinary cases until April 2017. As of August 2014, a total of 122 MATS compliance extension requests have been granted to U.S. coal and oil fired generating facilities. The main reasons for the extension requests were construction delays, retirement schedules and reliability assurance.

Regional Haze

In 1999, the EPA issued regulations to improve visibility particularly in national parks and recreation areas. Those regulations required states to develop plans, known as State Implementation Plans (SIPs), to address SO_2 and NOx emissions that contribute to regional haze. Among the required elements of these plans, states must include determinations of Best Available Retrofit Technology (BART) for certain types of sources that emit pollutants that impair visibility, and long term strategies to ensure that reasonable progress is being made.

In May 2012, the Environmental Protection Agency (EPA) issued a final action revising rules that pertain to how certain states can meet specific requirements of the agency's regional haze program. EPA's final action allows states participating in the Cross-State Air Pollution Rule (CSAPR) trading programs to use those programs in place of source-specific BART for SO_2 and/or NOx emissions from power plants that are subject to the regional haze rule. States not covered under CSAPR – western states such as Colorado, Utah, Arizona - are required to impose unit-specific emission limits and need to show reasonable progress towards reducing their emissions that impair visibility in class I areas. Units in these states will need to invest in additional expensive post combustion controls to limit SO_2 and NOx emissions if so required by the SIP. Most SIPs require compliance by 2018.

Clean Power Plan

With respect to the proposed CPP, EVA has reviewed the EPA's underlying assumptions of the four building blocks the EPA utilized to formulate the proposed CO_2 emission rate limits for each state, and based on EVA's expertise in energy market analysis, we are unable to accept the EPA's assumptions. The EPA's four building block assumptions are:

(1) Existing coal-fueled generating facilities could achieve a 6% heat rate improvement by 2020;

(2) Existing combined cycle gas turbines (CCGT) would average a 70% utilization rate per year starting 2020;

(3) States would employ renewable energy policies that would achieve 209% more renewable generation, nationally, from 2012 to 2030;

(4) States would achieve demand-side energy efficiency (EE) savings that would improve 250% nationally from 2020 to 2030.

EVA employed different assumptions for each building block based on its market knowledge, experience and analysis:

(1) EVA believes that existing coal-fueled generating facilities are already operating at very efficient levels and cannot achieve a 6% heat rate reduction on average for the entire coal fleet. EPA's analysis assuming that coal-fired power plants can improve efficiency simply by adopting "best practices" was flawed because it did not consider the major factors which cause some plants to be more efficient than others. Further, compliance with the EPA's MATS and other new and potential

regulations addressing a variety of issues (including cooling water, regional haze, and fine particulates) will increase parasitic load and reduce plant efficiency for existing coal-fired units. Additionally, if natural gas generation operates at significantly higher capacity factors, coal-fueled generating facilities would be relegated to follow load. The cycling of such facilities at lower operating levels would reduce any proposed heat rate efficiencies. As a result, EVA assumed on average no efficiency gain for the existing coal-fueled generation fleet.

(2) EPA's assumption that gas-fired CCGT's can operate at an average utilization rate of 70% does not reflect real-world experience or reasonable modeling of the U.S. power markets. EVA's production cost modeling allows CCGTs to run to utilization levels near 85% if economically required. The actual results from its power market analysis do not call for the CCGTs to dispatch at an average 70% utilization rate in the U.S. power markets. Neither the existing CCGTs nor newly constructed CCGTs reach the average utilization of 70% as referred to in the EPA Block 2.

(3) EVA employed an internally developed state-by-state forecast of renewable capacity deployment that not only takes into account each state's renewable portfolio standards (RPS), but also considers each individual state's economically reasonable renewable resource limitations and the cost effectiveness of each type of renewable capacity. EVA's estimates of non-hydro renewable generation (wind and solar) is forecast to grow from approximately 5% of the U.S. generation supply in 2012 to 7% by 2020 under the Administration's plan. EVA's non-hydro renewable generation estimate grows an additional 20% from 2020 to 2030. Interestingly, the renewable generation outlook EVA assumed is very similar to the outlook the EPA projected from its power modeling efforts. However, the EPA used a higher estimate of renewable generation to formulate its state-by-state CO_2 emission rate limits.

(4) EVA utilized research from the Electric Power Research Institute (EPRI) to create a realistically achievable outlook for demand-side energy efficiency implementation based on a consumer's adoption rate of energy efficient technologies. Using these more realistic assumptions, EVA's estimate of energy efficiency growth is half that of the EPA, as EVA assumed energy efficiency will increase 120% from 2020 to 2030.

In addition to these differences with EPA's building block assumptions, EVA used a higher level of gas demand for the industrial sector, as well as liquefied natural gas (LNG) and Mexican exports, than the EPA used when modeling the proposed CPP. The higher levels of demand are more reflective of current industrial sector demand and the increase in the number of permits for U.S. liquefaction terminals, as well as projections prepared by other third parties.

Using these assumptions, EVA then estimated CPP compliance costs, ensuring that each state meets EPA's proposed CO_2 rate target by EPA's designated 2020 (interim) and 2030 (final) milestones.

The EPA's CPP would result in significant development of new generating capacity, transmission lines, gas lines and other infrastructure, the cost of which is not discussed in the EPA's published results. The EPA does not appear to take into account the time required to pre-engineer, permit, engineer, procure and construct gas generation and transmission. EVA estimates between five to 10 years for such projects to move from planning to completion.

If the EPA's proposed CPP were to be enacted, it likely would occur in 2018 or later. However, U.S. power markets would not be able to meet electricity and gas reliability standards for such major generation and transmission changes until 2025 or later. Despite this reality, EVA did not incorporate the expected timelines to permit, engineer, procure and construct as part of its analysis.

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[1]EVA chose 2012 as the base year for purposes of this analysis because the EPA chose 2012 as the base year for its CPP proposal; however, it is worth noting that because the CPP was not officially in effect in 2012, any price increases that occurred prior to CPP enactment cannot be directly attributed to the CPP.

[2]Energy Cost Impacts on American Families, 2001-2014, Gene Trisko, ACCCE

[3]Real values are listed in parentheses immediately following nominal values throughout the Executive Summary.

[4]Inflation assumption sourced from Moody's Analytics: www.moodysanalytics.com

[5] Natural gas prices were at their lowest point in 2012 and rose over 25 percent between 2012 and 2014 as a result of factors not related to the proposed CPP.

Methodology

Problem Statement

EVA reviewed and analyzed the cumulative impact the EPA's Clean Power Plan proposal to regulate CO_2 emissions from existing power plants, recent air regulations (including the Mercury and Air Toxics Standards and Regional Haze regulations) and other market forces will have on consumer energy costs.

EVA prepared a forecast of future U.S. power and energy markets using a blend of EVA's realistic energy market assumptions and some of the EPA's basic assumptions, plus those necessary to meet the EPA's state emission rates as required by the CPP. EVA calls this the "2020 CO_2 Case."

For its analysis, EVA focused on EPA's Option 1 - State compliance scenario, in which the EPA created state CO_2 emission rate limits affecting existing power plants that must be achieved by 2030 and sustained thereafter.

This report highlights the increases in power and natural gas costs from 2012 to 2020 and compares them to the EPA's Option 1 – State compliance published results. The year 2020 is used for comparison purposes as it is the first year states will be required to implement major electricity system changes in order to meet EPA's interim CO_2 goals.[6]

Key Assumptions

MATS, Regional Haze and Other Recently-Finalized Power Sector Regulations

In response to MATS and Regional Haze Rules, the generation owners have installed controls for SO_2, NOx, mercury and particulates. Those controls added to the generation before 2012 are included in the base plant by plant modeling in order to meet the MATS and Regional Haze requirements. EVA tracked additional emission controls that have been added or will be added in 2012 through 2020 to meet these rules. The additions as detailed in the following table include over 30 GW of additional NOx controls, 44 GW of SO_2 controls and 28 GW of new particulate controls to a coal fleet that was approximately 315 GW in 2012.

In addition to emission control additions, 55 GW of coal plant retirements have been announced in part due to the series of federal regulations. These retirements are included in the baseline analysis. EVA estimated an additional 46 GW retirements of coal retirements in response to the proposed CPP.

Name Plate Capacity (MW)										
	2012	2013	2014	2015	2016	2017	2018	2019	2020	Total
NOx Controls										
SRC	5,186	3,194	3,448	4,285	1,246	3,415	2,696	1,300	188	24,957
SNCR	1,786	2,100	1,169	28	369	-	-	-	-	5,451
Total	6,972	5,294	4,617	4,313	1,615	3,415	2,696	1,300	188	30,408
SO_2 Controls										
Wet Scrubber	8,790	3,768	4,679	8,287	3,559	419	-	1,235	188	30,924
Dry Scrubber	3,043	1,008	824	759	-	261	-	-	-	5,895
Dry Sorbent Injection	-	642	3,564	2,453	473	-	-	-	-	7,132
Total	11,833	5,418	9,067	11,499	4,032	680	-	1,235	188	43,951
Particulate Controls										
Baghouse FF	4,213	2,052	3,450	8,247	5,792	680	-	-	188	24,622
Wet Scrubber	1,104	-	-	-	-	-	-	-	-	1,104
Electrostatic Precipitator	2,434	-	-	-	-	-	-	-	-	2,434
Total	7,751	2,052	3,450	8,247	5,792	680	-	-	188	28,160

Proposed Clean Power Plan

The first step in analyzing each scenario was to research and understand the four building blocks of the CPP[7] and the modeling assumptions used in the EPA's Integrated Planning Model.[8] After reviewing the EPA's assumptions, EVA evaluated the viability of each variable and determined the difference between its proprietary market assumptions and assumptions made by the EPA. EVA made the following assumptions regarding each of the EPA's four building blocks:

1. Coal Plant Heat Rate Improvements

The EPA assumes the utility industry can make a 6% improvement in each state's average coal unit heat rates through a combination of using best practices (4%) and an average capital upgrade investment of $100/kw (2%). The 4% was derived from a regression analysis using capacity factor and ambient temperature. The 2% was derived from a January 2009 Sargent and Lundy study "Coal-Fired Power Plant Heat Rate Reductions".

EVA assumed zero heat rate improvements for coal plants for several reasons:

First, insufficient technical data was provided to assess the EPA's regression analysis. This omission was included in a letter to EPA Administrator Gina McCarthy signed by the Attorneys General of 13 states.[9] There is no indication the analysis took into account coal rank, boiler type, and age, all of which affect heat rate. For example, a coal plant that has only super critical boilers has a heat rate materially lower than the heat rate of a plant with sub critical boilers. A regression analysis that only accounts for capacity factor and ambient temperature does not provide a reliable analysis on heat rate improvements.

Additionally, the EPA did not consider the impact of additional requirements related to compliance with MATS and other new and potential regulations including cooling water, regional haze and fine particulates on heat rate. Compliance with each of these new requirements will all increase parasitic load and reduce plant efficiencies.

The EPA did not consider the impact of natural gas dispatching at 70% utilization on coal plant capacity factors. Lower capacity factors will cause an increase in heat rates particularly if the lower capacity factors are due to the cycling of the units. As this is the likely outcome of natural gas re-dispatching, the heat rate improvements cannot be realized.

With regard to the EPA's capital investment assumption, the referenced Sargent and Lundy study looked at various methods to reduce heat rates of existing power plants by looking at "methods that have been successfully implemented by the utility sector." The study identified plant systems and equipment where efficiency improvements could be realized. Nowhere in the report did Sargent and Lundy conclude that average plant efficiencies for all coal-fired plants could be improved from 2008 levels (let alone current levels) by 2% for $100/kw. The study "cautions that the costs provided … are not indicative of those that may be expected for a specific facility … The costs should not be used as a basis for project budgeting or financing purposes." Yet this is precisely what the EPA has done.

2. CCGT Capacity Factor

The EPA states CO_2 rate limits are calculated using the assertion that existing CCGT plants will operate at a 70% capacity factor starting in 2020. EVA allowed its power dispatch model to determine how each existing CCGT plant would operate hourly based on market economics. The ultimate dispatch of the gas and coal plants was determined by utilizing the commercially-available AuroraXMP (Aurora) electric power market forecasting tool. Aurora is a fundamentals-based power market model that economically dispatches generation capacity to simulate the operations of each power market in the continental U.S.

3. State Renewable Outlook

Another measure the EPA used to reduce CO_2 emissions from existing fossil-fired power plants is the construction of new renewable energy generation such as solar, wind, biomass and geothermal to displace existing fossil fired generation. EPA relied on existing state Renewable Portfolio Standards (RPS) to estimate future regional renewable development potential and growth rates in its calculation of each state's CO_2 emission rate limit. Unfortunately, EPA's renewable methodology likely overestimates renewable potential by making no adjustments to exclude non-qualifying CPP compliance resources (e.g. hydro, EE, out-of-state resources) or special bonus incentives that several state RPS programs allow.

In developing the emission rate target limits, EPA assumed that qualifying non-hydro renewable generation would grow from 213 TWh in 2012 to 281 TWh by 2020. Interestingly, this assumption is considerably greater than the EPA's own power modeling results published in its regulatory impact analysis, where non-hydro renewable energy generation would reach 323 TWh in 2020.

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. EVA's modeled non-hydro renewable energy generation values are very similar to the EPA's modeling outputs, i.e. 301 TWh in 2020.

4. State Demand-Side Energy Efficiency Savings

According to the EPA, improved demand-side energy efficiency will cause 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 beginning in 2020.

The EPA energy efficiency savings for the lower 48 states in 2020 are estimated to be 119 TWh.[10] 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 the analysis performed as the basis of this report, 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. 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.

For the lower 48 states, EVA assumes 179 TWh in annual energy efficiency savings in 2020. 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 idea that these investments will be made independently of the EPA's CPP proposal.

Other Policy and Market Factors

There were a large number of energy market assumptions made in the EPA's and EVA's analyses, and the remaining assumptions are as follows:

1. Electricity Demand

The EPA sourced its electricity demand growth from the EIA's 2013 AEO. The "EIA's AEO reference case forecast includes some national energy efficiency (EE) and renewable energy (RE) policies, but does not include: 1) existing state EE policies and 2) future state EE policies. It is surmised that the EE savings from existing programs appears to be implicitly included through electricity sales forecasts."[11]

Using the AEO's 2013 data, the EPA's national electricity outlook assumed a compounded annual growth rate (CAGR) of 0.7% from 2012 to 2020 and 0.8% from 2020 to 2030 for its reference case. These growth rates do not include the additional energy efficiency that the EPA used to derive its state-by-state CO_2 emission rate limit rate. Applying the EPA's assumed energy efficiency projections to the base electricity demand outlook, nationally, electricity demand grows from 2012-2020 at a 0.3% CAGR and -0.1% from 2020 to 2030. Therefore, the EPA's energy efficiency assumption drives electricity demand growth negative post 2020.

EVA employed a proprietary econometric multiple regression model to estimate future electricity demand. The results from this demand model are combined with a state-by-state estimate of future energy efficiency. This analysis concluded that national electricity demand escalates at a CAGR of 0.6% from 2012 to 2020 and a 0.9% CAGR from 2020 to 2030.

To summarize, EVA and EIA have similar electricity demand growth expectations from 2012 through 2030. Because the EPA adds its aggressive energy efficiency expectations to the EIA's AEO 2013 electricity demand outlook, the EPA is effectively predicting an electricity demand outlook where the entire U.S. will reduce its electricity consumption by -0.1% per year 2020-2030. This negative electricity demand forecast is not consistent with the U.S. Department of Energy's Energy Information Agency (EIA), or other respected electricity demand forecasts.

Additionally, this assumption affects several key results in the regulatory analysis. For instance, negative electricity demand growth reduces the amount of power generation and fuel needed to meet electricity demand and limits the need for new generating capacity to meet electricity reserve margin targets. Therefore the cost impacts of the EPA's CPP will be less severe than they would be under a more realistic electricity demand assumption.

In conclusion, the EPA's negative electricity demand forecast is the direct result of its aggressive estimate of energy efficiency. This assumption has multiple impacts on the results of the EPA's regulatory impact analysis.

2. Natural Gas

In EPA's analysis of its proposed CPP, a proprietary set of natural gas models was used to evaluate the impact of the EPA's rule on the U.S. natural gas markets. Being proprietary, EVA had no access to these EPA models or any detailed descriptions of their construction or methodology. In order to produce a meaningful comparison of expected market outcomes across EPA and EVA assumptions, EVA used calibration methods to approximate EPA modeling structures across EVA's own set of proprietary natural gas models; these methods are outlined in the subsequent Modeling Description section.

The EPA concluded that natural gas demand stemming from the electric power sector in 2020 will rise to 26.1 billion-cubic feet per day (Bcfd), a 4.7% increase from the 24.9 Bcfd burned for electric generation in 2012. EVA's analysis illustrates a larger electric-power sector demand increase in 2020, to 31.3 Bcfd, a 25.6% increase from 2012 levels.

3. Coal

Each coal-fired electricity generation unit across the U.S. will consume coal that possesses specific qualities or a custom blend of two or more different types of coal depending on each coal plant's individual engineering operating parameters. Each of these different coal types is sourced from a different geographic location that has unique transportation logistics (rail, river, ocean, truck) and therefore costs. EPA applied broad and non-specific assumptions regarding the source and specifications for the coal consumed for each coal-fired generator in the electric power market. To perform a more robust analysis, EVA applied its proprietary set of detailed coal-related databases and forecast models to the coal portion of this regulatory analysis.

EPA's analysis estimates that coal generation will decline 14% from 2012 to 2020 and coal prices increase 33% during that period. When EPA's CPP is implemented in 2020, coal generation plummets 39% from 2018 while the average coal price declines 15%.

4. Nuclear Outlook

All nuclear generation currently under construction was completed for the purpose of this analysis. Additionally, nuclear was an option for new capacity and one not under-construction unit was modeled to be built in the analysis. As per the EPA's assumptions regarding nuclear life extensions, all existing nuclear units would get a 20 year operating extension after their 40 year term for reactor license expired. Hence the existing fleet of nuclear units would retire at the age of 60 years.

5. Reserve Margins

EVA utilized capacity reserve margin targets sourced from the North American Electric Reliability Corporation (NERC) and from each of the seven independent system operators in the U.S. These targets were used in each scenario analysis performed.

6. Capital Costs of New Generation

The cost and performance characteristics of conventional potential units contained in the EPA's analysis are derived primarily from assumptions used in the AEO 2013 reference case, published by the EIA. EVA decided to apply the same assumptions for each scenario analysis performed in order to reduce the number of dis-similarities between the EPA's and EVA's analysis.

7. Existing Unit Variable and Fixed Operating & Maintenance Costs

EPA's assumed variable and fixed operation and maintenance costs (VOM and FOM) were derived using a procedure jointly developed by the EPA's power sector engineering staff and ICF International.[12] In order to reduce differences between the EPA's CPP analysis and EVA, the VOM and FOM that the EPA assumed were applied to EVA's analysis.

However, EVA added $1.37/MWh to the EPA's reported VOM cost for coal-fired generating units to correctly include variable costs associated with water treatment and ash/sludge disposal, which the EPA's analysis did not include. Additionally, EVA used its own VOM cost estimates in cases where the EPA did not specify the exact costs related to a particular generation technology in their documentation.

8. Electricity Supply

Using a combination of announced and economic capacity retirements and new builds, EVA projects future electricity supply in the continental U.S. Through 2020, EVA retired roughly 101 GW of coal-based capacity, with an additional 5 GW being retired by 2030, for a cumulative total of 106 GW. This compares to the EPA assumption of 104 GW of coal-based capacity retiring by 2020 and an additional 15 GW, for a cumulative total of 119 GW, retiring by 2030.

In terms of new builds, EVA added over 123 GW of gas-based capacity by 2020 and 194 GW by 2030. In contrast, the EPA added 50 GW of gas-based capacity by 2020 and 65 GW by 2030. The major driver of this difference in net gas capacity added between the EVA cases and the EPA cases is the growth in electricity demand, which is higher in EVA's analysis, and the more aggressive renewable buildout that EPA assumed. The additional power demand in EVA's analysis keeps coal-fired capacity online as well as drives the need for additional gas-fired capacity to meet generation and reserve margin target requirements.

Because license expiry-driven nuclear retirements do not begin until roughly 2030, overall nuclear capacity in EVA's analysis stays fairly consistent throughout the study period, with the exception of five new reactors comprising 5.8 GW of capacity scheduled to come online between 2015 and 2019 in the Southeast. The EPA's analysis also shows very little net change in total nuclear capacity between 2018 and 2030, and it also includes the addition of five new reactors in the Southeast before 2020.

Overall capacity increases of 72 GW by 2020 and 137 GW by 2030 in EVA's analysis compared to 2012 (using AEO 2014 data). In EPA's analysis, total capacity decreases by nearly 26 GW and 4 GW by 2020 and 2030, respectively, due to significantly lower electricity demand.

9. Environmental Policy Assumptions

The EPA incorporated environmental policies that were enacted as of August 2013 in its analysis. In order to reduce differences between the EPA's CPP analysis and EVA for comparison purposes, EVA assumed the same environmental policies as the EPA.[13] Nevertheless, recent developments like the EPA's final rule on Cooling Water Intake 316(b), New Source Performance Standards (NSPS) for CO_2 emissions, and the likely changes to the Cross-State Air Pollution Rule (CSAPR) will have major impacts on the U.S. power industry that should have been considered in the EPA's analysis. To maintain consistency, they were not included in EVA's analysis either.

10. Emissions Allowance Prices

Differences and similarities can also be observed in the EPA's and EVA's emission allowance forecasts. Both methodologies forecast an oversupply of NOx annual, NOx seasonal, and SO_2 emission allowances under the EPA's Clean Air Interstate Rule (CAIR), resulting in emission allowance prices for all three types of allowances that equal zero through the modeling horizon for both reference and CPP-compliance scenarios. The methodologies do diverge when forecasting allowance prices for CO_2 emissions in existing CO_2 trading markets, such as the Regional Greenhouse Gas Initiative (RGGI) and California's cap-and-trade market under AB 32.

The EPA's forecasted AB 32 CO_2 emission allowance prices rise from $14.71/ton in 2020 to $18.21/ton in 2030, while RGGI CO_2 allowance prices range from $2.52/ton in 2020 to $4.97/ton in 2030. EVA's forecasted regional CO_2 allowance price for AB 32 escalates from $23/metric ton in 2020 to $38/metric ton in 2030. As for RGGI, EVA estimates that CO_2 allowance prices will range from $7/ton in 2020 to $13/ton in 2030.

The EPA's and EVA's contrasting emission prices potentially arise since EVA incorporates future developments in non-power sectors required to accumulate CO_2 allowances, as well as CO_2 offset project price developments and CO_2 allowance price elasticity effects. All of these factors will result in higher CO_2 allowance price forecasts when compared to EPA.

Modeling Description

The EVA analysis utilized a suite of energy market models to simulate the impact of recent federal regulations and then layer EPA's Clean Power Plan Option 1 - State compliance scenario on top of it. EVA modeling met each state-level CO_2 rate limit set out by the EPA's CPP in every year starting in 2020. Each state was required to meet the CO_2 rate limits with the resources within the state and could over-comply by as much as 5% in a given year. The following describes the major proprietary models that EVA used to estimate the results throughout this report.

Power Market Model

"EPA uses the Integrated Planning Model (IPM) to analyze the projected impact of environmental policies on the electric power sector in the 48 contiguous states and the District of Columbia. Developed by ICF Consulting, Inc. and used to support public and private sector clients, IPM is a multi-regional, dynamic, deterministic linear programming model of the U.S. electric power sector. It provides forecasts of least-cost capacity expansion, electricity dispatch, and emission control strategies for meeting energy demand and environmental, transmission, dispatch, and reliability constraints. IPM can be used to evaluate the cost and emissions impacts of proposed policies to limit emissions of sulfur dioxide (SO_2), nitrogen oxides (NOx), carbon dioxide (CO_2), hydrogen chloride (HCl), and mercury (Hg) from the electric power sector."[14]

EVA utilizes the commercially-available AuroraXMP (Aurora) electric power market forecasting tool. Aurora is a fundamentals-based power market model that economically dispatches generation capacity to simulate the operations of each power market in the continental U.S. The model optimizes dispatch by using the lowest cost resources to meet electricity demand in a given region at the hourly level and builds the most economic new resources to backfill for retirements and meet future load growth.

IPM and Aurora typically are used to support resource planning, regulatory analysis, commodity price forecasting, and asset valuation, and both seek to determine the least-cost method to meet electricity demand given various exogenous inputs and constraints.

Even though IPM and Aurora have similar goals, there are a couple differences between the models.

1. IPM aggregates similar types of capacity (fuel and technology type) and applies weighted-average operating parameters to the grouped capacity as opposed to populating the model with each generating unit and applying its real-life operating parameters. Therefore, IPM aggregates the 16,330 existing generating units in the electric power sector into 4,971 "model units" to simplify the analysis and reduce run time.

EVA populates the Aurora database with each power plant generator and does not aggregate multiple and different plants together. Therefore the Aurora model better simulates how each power plant operates in real-life on an hourly basis.

2. Regarding dispatch logic, IPM breaks up each model year into two seasons: winter and summer. The hourly demand in each season is then ordered from highest to lowest to develop a load duration curve, which IPM's aggregated units are then dispatched to create generation and power prices. IPM's methodology solves for the entire season at once, rather than dispatching units in each hour.

   The Aurora dispatch logic economically dispatches each generation unit against electricity demand for each chronological hour. Therefore, Aurora closely mimics the actual power markets' day-ahead and real-time dispatch practices and captures many of the unintended re-dispatch inefficiencies introduced by the CPP that a load duration curve based approach would not.

Coal Market Models

EVA possesses several proprietary models that estimate coal demand, supply and prices for each coal basin in North America. Since delivered coal prices for plants in the U.S. can vary by more than 100% and therefore impact the coal generation level dramatically, this proprietary modeling of the various coal types to specific coal plants is an important step in the process. These fundamental coal models are integrated with the Aurora power market dispatch model. The delivered coal price forecast model, which determines the most economic coal for each plant by coal basin and quality which meets emissions and operational constraints, provides delivered coal prices for each coal-fired generator into Aurora.

Aurora estimates how each coal-fired asset will operate on an hourly basis throughout the study period. These results are translated into a coal burn model that converts each coal plant's forecasted generation into coal consumption (tons) using the heat input for each power plant that is derived from Aurora. The resulting coal consumption by basin has been bench-marked against historical patterns given by basin prices. The known coal type switches for the various plants are included in the modeling as well to account for projected future switches that are likely to occur as delivered coal prices to the plants vary over time.

Natural Gas Models

In an attempt to compare and contrast the set of natural gas assumptions the EPA employed in its CPP analysis, EVA endeavored to better understand the natural gas supply model selected by the EPA. Being a proprietary model, EVA was not privy to the EPA's actual supply model or any detailed descriptions of its construction and methodology.

In the absence of this information, EVA utilized its own proprietary supply model, which has many of the same features of the EPA supply model, and produced results that were not dissimilar from those published by the EPA. EVA is confident it has a reasonable proxy of the EPA's supply model for natural gas.

EVA then took the EPA supply model proxy and applied EVA's proprietary demand modeling against it to develop EVA's natural gas price forecast, derived from EVA's demand assumptions and the EPA's supply model. The end result of this exercise was EVA's ability to compare the impact of the EPA's and EVA's differing demand assumptions across a controlled supply context: an apples-to-apples demand comparison. Key among these demand differences are:

- Total Non-Electric Sector Demand – the EPA is underestimating increases in non-electric sector gas demand as participants in the global economy respond to the persistence of competitive natural gas prices in the United States.
    - Non-Electric Sector Demand increase between EVA and EPA in year 2020:
        - EVA projects demand 2.9 trillion cubic feet (Tcf) higher than EPA or 8.0 Bcfd.
        - This increase represents 18.5% of EPA's forecasted Total Non-Electric Sector Primary Demand in 2020. Considering uniform demand throughout the year, EVA believes that EPA is missing 67 days of primary non-electric gas demand in 2020.
        - Non-Electric Sector Primary Demand is defined as residential, commercial, industrial and transportation.
- Total Export Demand – the EPA is underestimating the amount of exports set to begin in the United States. Over the past 3 years, the DOE has been issuing permits which usher in the initiation of seaborne LNG exports from the lower 48 states. This is a completely new feature in the U.S. gas economy. An additional underestimation of U.S. exports is found in the assessment of future pipeline exports to Mexico, where U.S. dry-gas imports are less costly than global LNG imports.
    - Total Export Demand (LNG and Mexico) increase between EVA and EPA in the year 2020:
        - 2.8 Tcf increase higher than EPA or 7.7 Bcfd
        - This increase is equal to 194% of EPA's forecasted Total Export Demand in 2020
- Total Non-Electric Demand plus Total Exports – These EPA underestimations of primary non-electric gas demand and exports total 21% of EPA's entire gas demand forecast for 2020. Essentially, EVA believes the EPA is underestimating the 2020 U.S. gas economy by 1/5th.
    - Total primary non-electric gas demand plus exports increase between EVA and the EPA for the year 2020:
        - 5.7 Tcf increase higher than EPA or 15.7 Bcfd

Impact to Consumers

The final portion of the analysis aimed to quantify the cumulative impact of MATS, Regional Haze regulations, other recent power sector regulations, and the proposed CPP to consumers. The Aurora model forecasts power generation costs, generation capacity costs, and wholesale power market prices, but consumers of electricity incur additional charges as well. Three components of power cost charged to consumers were considered:

1) Power Generation Cost: In states with regulated power markets, this is equal to the cost to generate power. In states with deregulated power markets, this is equal to the wholesale power price.

2) Capacity Cost: In regulated states, this is equal to the cost to build new generation capacity. In deregulated states, this is equal to the capacity market price.

3) Remaining Cost: This is all other costs that are charged to consumers, including but not limited to transmission, distribution and account servicing.

The following steps were taken to forecast the total cost to power consumers in 2020:

1) 2012 modeled total cost of generation and capacity was subtracted from EIA reported revenue from Retail Sales of Electricity to Ultimate Customers to quantify the "remaining cost" charged to consumers of electricity.

2) This remaining cost portion was escalated using a nominal inflation factor.[15]

3) 2020 electricity consumption was forecasted by applying state specific load growth assumptions to the 2012 EIA reported sales of electricity to retail customers in gigawatt hours (GWh).

4) 2020 revenue from power sales was calculated in two steps:

    a. The 2020 modeled cost of generation by state was scaled by the factor of total consumption to total generation to account for imports and exports of power between states. This figure was grossed up by 5% to account for transmission and distribution losses.

    b. The 2020 remaining cost portion was added to the cost from part a. (above).

5) 2020 power rates were calculated by dividing total revenue by total consumption.

The impact to the residential customer subset was then calculated using the following steps:

1) 2020 residential electricity consumption was forecasted by applying state specific load growth assumptions to the 2012 EIA reported sales of electricity to residential customers (in GWh).

2) 2020 residential revenue was calculated by applying the 2012 EIA reported ratio of residential electricity consumption to total electricity consumption to the forecasted 2020 total electricity consumption.

3) EVA performed a linear regression analysis to predict the number of electricity customers in each sector using the number of households as the independent variable. Historical customer data was sourced from the EIA, while the historical and forecasted number of households was sourced from Moody's analytics.

4) 2020 residential power rates were calculated by dividing residential revenue by residential consumption.

5) 2020 average annual residential power bills were calculated by dividing residential revenue by the number of residential customers.

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[6] The annual cost continues to increase in subsequent years, as EPA's requirements tighten and compliance efforts drive prices higher between 2020 and 2030.

[7] http://www.epa.gov/airmarkets/powersectormodeling/docs/EPA%20Base%20Case%20v5%2013%20Documentation%20Supplement%20for%20CPP_6_12_14.pdf

[8] http://www.epa.gov/airmarkets/progsregs/epa-ipm/BaseCasev513.html

[9] Request for Withdrawal (EPA-HQ-OAR-2013-062 and EPA-HQ-OAR-2013-0603 http://www.ago.wv.gov/pressroom/Documents/Section%20307%20Letter%20(August%2025,%202014).pdf

[10] http://www.epa.gov/airmarkets/powersectormodeling/docs/EPA%20Base%20Case%20v5%2013%20Documentation%20Supplement%20for%20CPP_6_12_14.pdf

[11] http://www.synapse-energy.com/Downloads/SynapseReport.2013-10.0.EE-in-AEO.12-094.pdf

[12] For more information: http://www.epa.gov/airmarkets/progsregs/epa-ipm/docs/v513/Chapter_4.pdf

[13] For more information: http://www.epa.gov/airmarkets/progsregs/epa-ipm/docs/v513/Chapter_3.pdf

[14] http://www.epa.gov/powersectormodeling/

[15] Inflation assumptions sourced from Moody's Analytics: http://www.moodysanalytics.com

Results

Power

Utilizing EVA's comprehensive economic dispatch model, detailed generation and capacity outlooks were developed.

Generation Capacity

The generation capacity mix from 2012 to 2020 in the CO_2 Case shifts sharply away from coal and towards natural gas and non-hydro renewables. 112 GW of coal, nuclear and hydro baseload capacity is slated to retire between 2013 and 2020. At the same time, 117 GW of gas capacity and 34 GW of non-hydro renewable capacity will be added.

U.S. Generation Capacity Mix: 2012 vs. 2020 CO_2 Case			
Fuel	**2012**	**2020**	**Change**
Coal	31%	20%	-11%
Natural Gas	41%	50%	9%
Nuclear	10%	10%	0%
Renewables	7%	10%	3%
Hydro	10%	9%	-1%
Other	2%	1%	-1%

Generation

Implementation of the CPP would create a dramatic shift in the nation's generation mix, most notably affecting the roles of coal and natural gas. The CPP would skew the generation mix towards natural gas and renewable generation and away from coal. The proposal would cut coal generation by 40% while increasing natural gas generation by 67%, resulting in a generation portfolio consisting of 49% traditional baseload sources (coal, nuclear and hydro), 45% natural gas, and 7% non-hydro renewable generation.

U.S. Generation Mix: 2012 vs. 2020 CO_2 Case			
Fuel	**2012**	**2020**	**Change**
Coal	39%	22%	-17%
Natural Gas	29%	45%	16%
Nuclear	20%	20%	0%
Renewables	5%	7%	2%
Hydro	7%	7%	0%
Other	0%	0%	0%

The following table reflects state-by-state generation mix results changes between 2012 and 2020 under the CPP. The states with the greatest swings in generation mix under the CPP program are projected to be Missouri, Arkansas, Maryland, Indiana, Kentucky and Louisiana, with higher cost gas generation increasing on average 39% while generally reducing lower cost coal generation a similar amount.

U.S. Generation Mix Comparison: 2012 vs. 2020 CO_2 Case								
Fuel	Coal		Natural Gas		Renewables		Other	
State	2012	2020	2012	2020	2012	2020	2012	2020
Alabama	31%	23%	36%	42%	0%	1%	32%	35%
Arizona	36%	20%	27%	43%	2%	3%	35%	34%
Arkansas	45%	6%	27%	66%	0%	1%	28%	27%
California	1%	0%	58%	60%	16%	21%	25%	19%
Colorado	66%	39%	19%	44%	12%	12%	3%	5%
Connecticut	0%	4%	46%	37%	4%	5%	50%	54%
Delaware	18%	11%	80%	86%	2%	2%	0%	0%
Florida	21%	8%	69%	78%	2%	3%	8%	12%
Georgia	35%	14%	35%	49%	0%	1%	30%	37%
Idaho	0%	0%	12%	28%	14%	16%	73%	56%
Illinois	41%	31%	5%	16%	4%	8%	50%	45%
Indiana	83%	45%	13%	49%	3%	5%	0%	1%
Iowa	61%	49%	3%	17%	26%	25%	9%	8%
Kansas	63%	52%	6%	19%	12%	15%	19%	14%
Kentucky	94%	57%	3%	39%	0%	0%	3%	5%
Louisiana	33%	0%	45%	82%	0%	0%	22%	17%
Maine	0%	0%	43%	30%	25%	34%	32%	36%
Maryland	51%	26%	5%	44%	3%	2%	41%	28%
Massachusetts	7%	0%	69%	78%	6%	6%	19%	16%
Michigan	50%	28%	20%	41%	3%	4%	27%	27%
Minnesota	44%	31%	13%	24%	18%	20%	25%	25%
Mississippi	14%	12%	72%	57%	0%	1%	14%	31%
Missouri	79%	23%	7%	53%	1%	5%	13%	19%
Montana	52%	51%	2%	2%	6%	7%	41%	41%
Nebraska	73%	46%	2%	2%	4%	11%	21%	42%
Nevada	12%	2%	73%	76%	8%	18%	7%	5%
New Hampshire	7%	5%	37%	14%	7%	18%	49%	63%
New Jersey	3%	1%	43%	63%	2%	2%	52%	33%
New Mexico	69%	62%	24%	23%	7%	14%	1%	2%
New York	3%	2%	44%	44%	4%	7%	49%	48%
North Carolina	44%	20%	17%	37%	1%	1%	38%	42%
North Dakota	78%	77%	0%	2%	15%	16%	7%	5%
Ohio	68%	51%	17%	37%	1%	1%	14%	11%
Oklahoma	38%	14%	50%	74%	11%	10%	1%	2%
Oregon	4%	0%	19%	40%	11%	16%	65%	44%
Pennsylvania	40%	28%	23%	38%	2%	2%	35%	32%
Rhode Island	0%	0%	99%	92%	1%	6%	0%	2%
South Carolina	30%	18%	15%	21%	1%	1%	55%	60%
South Dakota	25%	12%	2%	9%	24%	27%	50%	51%
Tennessee	45%	22%	10%	22%	0%	0%	44%	55%

Table Continued on Next Page

U.S. Generation Mix Comparison: 2012 vs. 2020 CO_2 Case								
Fuel	Coal		Natural Gas		Renewables		Other	
State	2012	2020	2012	2020	2012	2020	2012	2020
Texas	36%	20%	46%	58%	8%	12%	10%	10%
Utah	79%	38%	16%	41%	3%	13%	2%	8%
Vermont	0%	0%	0%	0%	7%	39%	93%	61%
Virginia	20%	10%	36%	51%	2%	4%	42%	35%
Washington	3%	0%	5%	10%	6%	8%	85%	82%
West Virginia	97%	71%	0%	22%	2%	6%	1%	2%
Wisconsin	52%	29%	18%	35%	4%	7%	25%	30%
Wyoming	89%	77%	0%	12%	9%	9%	2%	2%
United States	39%	22%	29%	45%	5%	7%	27%	27%

U.S. Cost Impact

The results of EVA's cost impact analysis show substantial cost increases to electricity customers between 2012 and 2020. The total cost of power to consumers in general consists of the cost of generation and the capital investments for new capacity builds. The method by which these costs are determined differs depending upon whether the state is a regulated or deregulated cost of service state.

For states that have a regulated cost of service, production costs (fuel, operating and maintenance cost) and the capital cost of new generation are charged back to customers.

For states that have deregulated electricity prices, customers pay the wholesale energy market price plus the capacity market price. Capacity market prices increase from very minimal levels in 2012 to much higher levels in many states that are required to build new gas peaker and NGCC capacity to maintain proper reserve margins in light of considerable coal plant retirements.

Below is a list of states with regulated power markets.

States with Regulated Electricity Markets		
Alabama	Kentucky	Oklahoma
Arizona	Louisiana	South Carolina
Arkansas	Minnesota	South Dakota
California	Mississippi	Tennessee
Colorado	Missouri	Utah
Florida	Montana	Vermont
Georgia	Nebraska	Virginia
Idaho	Nevada	Washington
Indiana	New Mexico	West Virginia
Iowa	North Carolina	Wisconsin
Kansas	North Dakota	Wyoming

Cost Impacts in Regulated States

The national generation weighted average production cost in regulated states in 2012 was \$21/MWh. The costs increase to \$43/MWh under the 2020 CO_2 Case. The state-by-state production cost increases vary significantly between states depending on the primary fuel or fuels used to generate electricity. Several states have added capital costs for new generation, but given these cost increases are spread across all the customers in the state, they have a much smaller impact than capacity additions in deregulated states. The states with the largest percentage increases, such as Mississippi, Nevada, Colorado, Montana and Wyoming, are also among the states with the largest overall electricity cost to consumer increases.

Electricity Production Cost in Regulated States (\$/MWh): 2012 vs. 2020 CO_2 Case

State	2012	2020	Increase	2020	Increase
	Nominal Dollars			Real 2012 Dollars	
Alabama	19.39	42.51	119%	36.27	87%
Arizona	18.92	46.16	144%	39.39	108%
Arkansas	20.27	43.77	116%	37.35	84%
California	21.09	40.35	91%	34.44	63%
Colorado	22.95	57.96	153%	49.46	116%
Florida	24.20	53.66	122%	45.79	89%
Georgia	21.54	42.11	96%	35.93	67%
Idaho	9.16	22.56	146%	19.25	110%
Indiana	26.16	54.62	109%	46.61	78%
Iowa	20.28	38.80	91%	33.11	63%
Kansas	19.68	40.93	108%	34.92	77%
Kentucky	26.40	58.33	121%	49.77	89%
Louisiana	22.06	48.61	120%	41.48	88%
Minnesota	20.98	39.35	88%	33.57	60%
Mississippi	23.36	75.85	225%	64.73	177%
Missouri	21.78	46.55	114%	39.72	82%
Montana	11.51	30.28	163%	25.84	125%
Nebraska	17.57	35.15	100%	30.00	71%
Nevada	24.08	63.56	164%	54.23	125%
New Mexico	25.56	42.91	68%	36.61	43%
North Carolina	22.01	38.58	75%	32.92	50%
North Dakota	20.32	41.61	105%	35.51	75%
Oklahoma	22.10	52.09	136%	44.45	101%
South Carolina	16.60	31.22	88%	26.64	60%
South Dakota	13.37	17.56	31%	14.99	12%
Tennessee	16.75	34.95	109%	29.83	78%
Utah	26.01	57.91	123%	49.42	90%
Vermont	8.67	10.15	17%	8.66	0%
Virginia	19.38	39.77	105%	33.93	75%
Washington	8.08	14.33	77%	12.22	51%
West Virginia	31.18	58.87	89%	50.23	61%
Wisconsin	22.64	45.83	102%	39.11	73%
Wyoming	18.85	47.89	154%	40.86	117%

Cost Impacts in Deregulated States

For deregulated states, changes in wholesale prices in combination with capacity prices are the effective “Energy Portion” changes in the customer’s total electric bill. The national generation weighted average wholesale power cost in deregulated markets in 2012 was $30/MWh. The costs increase to $68/MWh under the 2020 CO_2 case. The increases in wholesale power prices (as seen below) vary state-by-state as each state implements recent power sector final regulations and the proposed CPP. The states with the largest increases, such as Oregon, Texas and Illinois, are also among the states with the largest overall electricity cost to consumer increases. Given additional generation capacity needed by 2020, capacity market prices also increase to incent the building of new generation capacity. The cost increases in the deregulated states tend to be higher than those in regulated states and therefore the largest overall customer increases tend to be in deregulated states, except Mississippi.

Wholesale Power Price in Deregulated States ($/MWh): 2012 vs. 2020 CO_2 Case					
State	**2012**	**2020**	**Increase**	**2020**	**Increase**
	Nominal Dollars			Real 2012 Dollars	
Connecticut	34.97	78.28	124%	66.80	91%
Delaware	33.60	64.89	93%	55.37	65%
Illinois	25.68	66.39	159%	56.65	121%
Maine	34.97	78.56	125%	67.04	92%
Maryland	35.85	64.93	81%	55.41	55%
Massachusetts	34.97	81.93	134%	69.92	100%
Michigan	29.86	67.14	125%	57.30	92%
New Hampshire	34.97	79.75	128%	68.06	95%
New Jersey	28.32	64.89	129%	55.37	96%
New York	35.35	63.99	81%	54.60	54%
Ohio	30.68	66.33	116%	56.60	85%
Oregon	21.44	79.47	271%	67.81	216%
Pennsylvania	35.85	65.15	82%	55.60	55%
Rhode Island	34.97	82.71	137%	70.58	102%
Texas	25.63	69.83	172%	59.59	132%

Total Electricity Cost to Consumers

EVA expects the cost of power to consumers to increase by $177 billion ($98 billion), or 49% (27%), from 2012 to 2020 in the 2020 CO_2 Case. The dramatic shift towards higher levels of gas-fired generation occurs as gas prices increase due to market and regulatory factors. Particularly hard hit would be states that are forced to move from a coal-heavy generation portfolio to one more dependent on other sources. States such as Texas, Mississippi, Illinois, Oregon and Oklahoma would see annual power costs increase by an average of roughly 80% in 2020 when compared to 2012. Following is a table of the state-by-state impact of total electricity cost increases from 2012 to 2020 for the state under the 2020 CO_2 Case.

Electricity Cost Increases ($BB): 2012 vs. 2020 CO_2 Case					
State	2012	2020	Increase	2020	Increase
	Nominal Dollars			Real 2012 Dollars	
Alabama	7.9	11.7	48%	10.0	27%
Arizona	7.3	10.4	41%	8.9	21%
Arkansas	3.5	5.6	57%	4.7	34%
California	35.6	45.9	29%	39.2	10%
Colorado	5.0	7.8	55%	6.7	32%
Connecticut	4.6	6.6	45%	5.7	23%
Delaware	1.3	1.9	50%	1.6	28%
Florida	23.0	34.1	48%	29.1	26%
Georgia	12.2	17.3	42%	14.7	21%
Idaho	1.6	2.1	33%	1.8	13%
Illinois	12.1	20.4	68%	17.4	44%
Indiana	8.6	13.0	51%	11.1	29%
Iowa	3.5	5.1	44%	4.4	23%
Kansas	3.7	5.3	43%	4.5	22%
Kentucky	6.4	10.5	64%	9.0	40%
Louisiana	5.8	9.0	55%	7.7	32%
Maine	1.4	1.8	28%	1.5	10%
Maryland	7.0	10.7	53%	9.1	30%
Massachusetts	7.6	11.8	55%	10.0	32%
Michigan	11.5	17.7	54%	15.1	32%
Minnesota	6.0	8.3	38%	7.1	18%
Mississippi	4.1	7.6	84%	6.5	57%
Missouri	7.0	11.2	60%	9.5	37%
Montana	1.1	1.6	42%	1.4	21%
Nebraska	2.5	3.5	38%	3.0	18%
Nevada	3.1	4.8	53%	4.1	31%
New Hampshire	1.5	2.4	55%	2.0	32%
New Jersey	10.4	16.1	54%	13.7	32%
New Mexico	2.1	2.7	33%	2.3	14%
New York	21.7	30.3	40%	25.9	19%
North Carolina	11.6	15.6	34%	13.3	15%
North Dakota	1.1	1.8	56%	1.5	34%
Ohio	13.8	21.2	54%	18.1	31%
Oklahoma	4.4	7.2	64%	6.2	40%
Oregon	3.8	6.9	78%	5.9	52%
Pennsylvania	14.3	22.7	59%	19.4	36%
Rhode Island	1.0	1.6	64%	1.4	40%
South Carolina	7.0	9.6	37%	8.2	17%
South Dakota	1.0	1.2	20%	1.0	3%
Tennessee	9.0	12.4	38%	10.6	18%
Texas	31.4	60.8	93%	51.9	65%

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Electricity Cost Increases ($BB): 2012 vs. 2020 CO_2 Case					
State	2012	2020	Increase	2020	Increase
	Nominal Dollars			Real 2012 Dollars	
Utah	2.3	3.2	38%	2.7	18%
Vermont	0.8	1.0	26%	0.8	7%
Virginia	9.8	13.6	39%	11.6	18%
Washington	6.4	8.0	24%	6.8	6%
West Virginia	2.5	3.4	36%	2.9	16%
Wisconsin	7.1	10.0	41%	8.5	20%
Wyoming	1.2	1.9	60%	1.7	36%
United States	364	541	49%	462	27%

Electricity Bill Increase to Households

The burden felt by residential customers would be onerous as well. The average residential customer's annual power bill would be about $340 higher ($102 in real dollars) in 2020 compared to 2012 in the 2020 CO_2 Case. Families in Mississippi would pay over $850 ($514) more in annual power bills, while the average household in the five hardest hit states (Mississippi, Texas, Pennsylvania, Maryland, Rhode Island) would see an average increase of more than $660 in their annual power bills. Illinois and New Hampshire replace Maryland and Pennsylvania in the top five hardest hit on a percentage basis with these states averaging over a 50% increase. It generally appears that states with high levels of both coal and underutilized combined-cycle generation tend to experience very high generation shifts and cost increases (e.g., Texas, Illinois and Mississippi). Following is a table of the state-by-state impacts to residential customers under the 2020 CO_2 Case.

Average Annual Residential Electricity Bill ($): 2012 vs. 2020 CO_2 Case					
State	2012	2020	Increase	2020	Increase
	Nominal Dollars			Real 2012 Dollars	
Alabama	1,622	2,064	27%	1,762	9%
Arizona	1,436	1,478	3%	1,261	-12%
Arkansas	1,241	1,682	36%	1,435	16%
California	1,071	1,193	11%	1,018	-5%
Colorado	972	1,229	26%	1,049	8%
Connecticut	1,519	2,024	33%	1,727	14%
Delaware	1,548	1,935	25%	1,651	7%
Florida	1,479	1,752	18%	1,495	1%
Georgia	1,463	1,673	14%	1,427	-2%
Idaho	1,026	1,148	12%	979	-5%
Illinois	1,040	1,514	46%	1,292	24%
Indiana	1,232	1,615	31%	1,378	12%
Iowa	1,139	1,447	27%	1,235	8%

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Average Annual Residential Electricity Bill ($): 2012 vs. 2020 CO_2 Case					
State	2012	2020	Increase	2020	Increase
	Nominal Dollars			Real 2012 Dollars	
Kansas	1,256	1,587	26%	1,354	8%
Kentucky	1,265	1,714	36%	1,463	16%
Louisiana	1,256	1,702	36%	1,453	16%
Maine	936	1,133	21%	967	3%
Maryland	1,549	2,101	36%	1,793	16%
Massachusetts	1,114	1,572	41%	1,341	20%
Michigan	1,145	1,545	35%	1,318	15%
Minnesota	1,087	1,287	18%	1,099	1%
Mississippi	1,467	2,321	58%	1,981	35%
Missouri	1,284	1,775	38%	1,515	18%
Montana	1,023	1,237	21%	1,056	3%
Nebraska	1,209	1,494	24%	1,275	5%
Nevada	1,326	1,489	12%	1,271	-4%
New Hampshire	1,190	1,714	44%	1,462	23%
New Jersey	1,337	1,877	40%	1,601	20%
New Mexico	902	1,033	15%	882	-2%
New York	1,279	1,684	32%	1,437	12%
North Carolina	1,396	1,534	10%	1,309	-6%
North Dakota	1,182	1,568	33%	1,338	13%
Ohio	1,250	1,706	36%	1,456	16%
Oklahoma	1,279	1,801	41%	1,537	20%
Oregon	1,130	1,586	40%	1,354	20%
Pennsylvania	1,284	1,840	43%	1,570	22%
Rhode Island	1,033	1,643	59%	1,402	36%
South Carolina	1,568	1,773	13%	1,513	-4%
South Dakota	1,183	1,239	5%	1,058	-11%
Tennessee	1,484	1,783	20%	1,522	3%
Texas	1,551	2,299	48%	1,962	26%
Utah	945	1,069	13%	912	-3%
Vermont	1,168	1,412	21%	1,205	3%
Virginia	1,483	1,744	18%	1,488	0%
Washington	1,060	1,123	6%	958	-10%
West Virginia	1,273	1,609	26%	1,373	8%
Wisconsin	1,120	1,383	24%	1,180	5%
Wyoming	1,026	1,365	33%	1,165	14%
United States	**1,288**	**1,629**	**27%**	**1,390**	**8%**

Electricity Price Increases to Industrial Customers

Energy intensive industries like aluminum, steel and chemicals manufacturing must have affordable energy prices to compete on a global scale. The average price of electricity to industrial customers will be 56% (33%) higher in 2020 compared to 2012 in the 2020 CO_2 Case. The average industrial customer is hardest hit in Texas, Illinois, Mississippi and Oregon, where customers would see their power prices almost double on average from just under six cents/kWh to almost 12 cents/kWh. Following is a table of the state-by-state impacts to industrial power prices in the 2020 CO_2 Case.

Industial Electricity Rates (¢/kWh): 2012 vs. 2020 CO_2 Case					
State	**2012**	**2020**	**Increase**	**2020**	**Increase**
	Nominal Dollars			**Real 2012 Dollars**	
Alabama	6.2	8.9	43%	7.6	22%
Arizona	6.5	8.9	36%	7.6	16%
Arkansas	5.7	8.7	54%	7.4	31%
California	10.7	13.5	26%	11.5	8%
Colorado	6.9	10.5	52%	9.0	30%
Connecticut	12.8	18.7	46%	15.9	25%
Delaware	8.3	12.5	50%	10.7	28%
Florida	8.0	11.4	42%	9.8	21%
Georgia	5.9	8.2	40%	7.0	19%
Idaho	5.6	6.8	22%	5.8	4%
Illinois	5.9	11.2	89%	9.5	61%
Indiana	6.4	9.5	50%	8.1	28%
Iowa	5.3	7.3	37%	6.2	17%
Kansas	6.9	9.8	43%	8.4	22%
Kentucky	5.4	9.3	74%	7.9	49%
Louisiana	4.8	7.0	48%	6.0	27%
Maine	7.9	10.1	28%	8.6	9%
Maryland	8.1	12.9	59%	11.0	35%
Massachusetts	12.9	20.4	58%	17.4	35%
Michigan	7.7	12.6	63%	10.8	39%
Minnesota	6.6	8.8	34%	7.5	14%
Mississippi	6.2	12.2	99%	10.4	69%
Missouri	5.9	9.3	60%	8.0	36%
Montana	5.0	7.2	44%	6.2	23%
Nebraska	6.8	9.2	35%	7.9	16%
Nevada	6.5	9.5	48%	8.1	26%
New Hampshire	11.8	18.5	57%	15.8	34%
New Jersey	10.5	16.0	52%	13.6	29%
New Mexico	5.8	7.5	29%	6.4	10%
New York	6.7	10.6	59%	9.0	35%
North Carolina	6.3	8.0	26%	6.8	8%

Table Continued on Next Page

Industial Electricity Rates (¢/kWh): 2012 vs. 2020 CO_2 Case					
State	2012	2020	Increase	2020	Increase
Nominal Dollars				Real 2012 Dollars	
North Dakota	6.7	8.7	30%	7.4	11%
Ohio	6.2	10.8	74%	9.2	48%
Oklahoma	5.0	8.5	70%	7.3	45%
Oregon	5.6	11.3	102%	9.7	72%
Pennsylvania	7.2	11.7	62%	10.0	38%
Rhode Island	10.9	18.2	67%	15.5	43%
South Carolina	6.0	7.7	30%	6.6	11%
South Dakota	6.6	6.6	1%	5.7	-14%
Tennessee	7.1	9.3	31%	8.0	12%
Texas	5.7	12.1	112%	10.4	81%
Utah	5.6	7.4	31%	6.3	12%
Vermont	10.0	12.3	23%	10.5	5%
Virginia	6.7	8.7	30%	7.4	11%
Washington	4.1	4.8	17%	4.1	0%
West Virginia	6.3	8.5	34%	7.2	14%
Wisconsin	7.4	10.4	41%	8.9	20%
Wyoming	6.0	9.5	58%	8.1	35%
United States	6.7	10.5	56%	8.9	33%

Natural Gas

The shale revolution has allowed U.S. consumers to enjoy inexpensive natural gas over the past several years, with prices averaging $2.82/mmbtu in 2012. However, prices increased over 30% in 2013 to an average of $3.73/mmbtu, and are expected to increase from these low levels over the next decade.

At least three events are expected to significantly move U.S. natural gas demand higher through 2020.

1) U.S. industrial production will continue to shift its fuel supply to natural gas in order to benefit from economical natural gas prices. EVA estimated the industrial sector's consumption of natural gas is predicted to increase at an average annual rate of 4% from 2012 to 2020.

2) With a large supply of economic natural gas reserves, the U.S. is predicted to begin exporting LNG in 2018. Additionally, exports to Mexico will continue to rise as new infrastructure is put in place. By 2020, EVA estimates that 13.3 Bcfd will be exported from the U.S. (8.4 Bcfd net exports, 4.9 Bcfd exports to Mexico).

3) Lastly, as the CPP is implemented in 2020, natural gas consumption in the electric power sector will escalate rapidly. In order for states and power markets to comply with EPA's carbon rate limits, existing coal-fired and gas-fired plants' utilization will be limited. However, newly constructed gas-fired plants will not be covered under the CPP, therefore new NGCC plants will be constructed to meet electricity demand. EVA estimates that natural gas demand in the electric power sector will escalate 26% between 2012 and 2020.

Collectively, natural gas demand from exports, industrial consumption and electric power sector is estimated to escalate 52% from 2012 to 2020 and will account for 70% of the total natural gas demand in 2020. EVA estimates that Henry Hub prices will increase to 2.3 times 2012 levels, reaching $6.62/mmbtu in 2020, in line with the EPA's estimates in its CPP modeling.

Overview of U.S. Natural Gas Supply, Demand and Prices		
Bcfd	**2012**	**2020 CO_2 Case**
Supply		
Total Production	65.9	98.5
Net Canadian Imports	5.4	3.7
Net LNG Imports	0.4	0.0
Total Supply	**71.7**	**102.2**
Demand		
Residential	11.3	12.9
Commercial	7.9	9.5
Industrial	19.7	26.7
Electric	24.9	31.3
Transportation	0.1	1.2
Other	5.8	7.3
Net LNG Exports	0.0	8.4
Net Mexican Exports	1.7	4.9
Total Demand	**71.4**	**102.2**
Henry Hub Prices - $ MMBtu		
Nominal	2.82	6.62
Real 2012 $	2.82	5.65

U.S. Average Annual Non-Electric Customer Natural Gas Bill			
	2012	**2020 CO_2 Case**	**2020 CO_2 Case**
Residential Prices ($/mmbtu)		**Nominal**	**Real**
Gas Supply Cost	2.82	6.62	5.65
Fixed Cost Component	7.80	9.15	7.80
Total Unit Cost	10.62	15.77	13.45
Total Annual Household Bill	**$675**	**$1,014**	**$865**
Commercial Prices ($/mmbtu)			
Gas Supply Cost	2.82	6.62	5.65
Fixed Cost Component	5.35	6.27	5.35
Total Unit Cost	8.17	12.89	11.00
Total Annual Business Bill	**$4,498**	**$8,556**	**$7,301**
Industrial Prices ($/mmbtu)			
Gas Supply Cost	2.82	6.62	5.65
Fixed Cost Component	2.18	2.55	2.18
Total Unit Cost	5.00	9.17	7.83
Total Annual Business Bill	**$189,832**	**$459,838**	**$392,395**
Total U.S. Non-Electric Sector Spend			
Billions of Dollars	$106.7	$213.2	$181.9
U.S. GDP			
Billions of Dollars	$16,245	$23,063	$19,681
Total U.S. Non-Electric Sector Spend as a Percentage of US GDP	0.66%	0.92%	0.92%

Cost to Consumers

An additional consequence of the increased reliance on gas-fired generation under the CPP is the impact felt by consumers of natural gas outside of the electric power sector. Natural gas serves as a feedstock in many industrial processes and is used for heating and cooking, among other things, in the homes of over 65 million residential customers in the U.S. As demand for natural gas for electricity generation increases, EVA predicts the price of gas to rise as well, increasing the amount that consumers pay for natural gas.

The net increase in the annual cost of natural gas in the U.S. between 2012 and 2020 is projected to be over $105 billion ($75 billion in real dollars adjusted for inflation) in the 2020 CO_2 Case, rising from $107 billion in 2012 to $213 billion ($182 billion) in 2020. Similar to the effect of increasing power prices, the industrial sector would be adversely affected by the increase in gas prices as well. Considerable growth in industrial output in the Southeast and South Central regions of the U.S. would be put at risk as manufacturers' cost structures change with rising gas prices.

Natural Gas Cost Increases ($BB): 2012 vs. 2020 CO_2 Case					
State	2012	2020	Increase	2020	Increase
	Nominal Dollars			Real 2012 Dollars	
Alabama	1.5	2.9	95%	2.5	66%
Arizona	1.0	1.7	73%	1.5	48%
Arkansas	1.2	2.2	87%	1.9	59%
California	10.6	17.6	66%	15.1	42%
Colorado	1.8	3.4	93%	2.9	64%
Connecticut	1.2	2.4	101%	2.0	72%
Delaware	0.6	0.9	56%	0.8	33%
Florida	1.5	2.7	72%	2.3	47%
Georgia	2.8	5.3	87%	4.5	60%
Idaho	0.5	0.8	70%	0.7	45%
Illinois	6.2	12.9	110%	11.0	79%
Indiana	3.8	7.9	108%	6.7	77%
Iowa	1.7	4.8	186%	4.1	144%
Kansas	1.2	2.2	86%	1.9	59%
Kentucky	1.1	2.2	98%	1.9	69%
Louisiana	3.7	15.3	311%	13.1	250%
Maine	0.4	0.8	80%	0.7	53%
Maryland	1.6	2.7	63%	2.3	39%
Massachusetts	2.8	4.4	59%	3.7	36%
Michigan	5.5	9.7	77%	8.3	51%
Minnesota	2.2	4.3	97%	3.6	68%
Mississippi	0.9	2.2	151%	1.9	114%
Missouri	2.1	3.5	67%	3.0	42%
Montana	0.5	0.8	76%	0.7	50%
Nebraska	0.8	1.6	94%	1.4	66%
Nevada	0.7	1.1	69%	1.0	44%
New Hampshire	0.3	0.4	50%	0.3	28%
New Jersey	4.1	6.9	68%	5.9	43%

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Natural Gas Cost Increases ($BB): 2012 vs. 2020 CO_2 Case					
State	2012	2020	Increase	2020	Increase
	Nominal Dollars			Real 2012 Dollars	
New Mexico	0.5	0.9	72%	0.8	47%
New York	7.3	13.5	84%	11.5	57%
North Carolina	1.8	3.4	87%	2.9	60%
North Dakota	0.2	1.1	343%	0.9	278%
Ohio	5.0	9.2	83%	7.8	56%
Oklahoma	2.3	4.0	74%	3.4	49%
Oregon	1.1	1.8	67%	1.6	42%
Pennsylvania	5.6	10.1	81%	8.6	54%
Rhode Island	0.4	0.6	45%	0.5	24%
South Carolina	0.9	1.6	88%	1.4	61%
South Dakota	0.4	0.7	98%	0.6	69%
Tennessee	1.5	2.9	99%	2.5	69%
Texas	7.9	20.9	166%	17.9	127%
Utah	0.9	1.7	79%	1.4	53%
Vermont	0.1	0.2	65%	0.1	40%
Virginia	1.8	3.0	68%	2.6	44%
Washington	2.2	3.3	49%	2.8	27%
West Virginia	0.5	0.9	71%	0.8	46%
Wisconsin	2.4	4.3	80%	3.6	53%
Wyoming	0.4	0.8	89%	0.7	61%
United States	107	214	100%	182	71%

The average residential customer would pay about $340 ($190 in real dollars) or 50% (28%) more for natural gas in 2020 than they did in 2012 under the 2020 CO_2 Case. Several of the most impacted states in terms of gas cost increases include states in the Northeast and Upper Midwest which consume the largest volumes of natural gas per home. In these states increases to annual residential gas bills would be over $1,000 more ($775) in 2020 on average than they were in 2012.

Average Annual Residential Natural Gas Bill ($): 2012 vs. 2020 CO_2 Case					
State	2012	2020	Increase	2020	Increase
	Nominal Dollars			Real 2012 Dollars	
Alabama	596	956	60%	816	37%
Arizona	485	584	20%	499	3%
Arkansas	580	1,038	79%	886	53%
California	417	544	30%	464	11%
Colorado	579	935	61%	798	38%
Connecticut	1,165	2,363	103%	2,016	73%
Delaware	862	1,143	33%	975	13%
Florida	392	584	49%	498	27%
Georgia	934	1,465	57%	1,250	34%

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Average Annual Residential Natural Gas Bill ($): 2012 vs. 2020 CO_2 Case					
State	2012	2020	Increase	2020	Increase
	Nominal Dollars			Real 2012 Dollars	
Idaho	572	742	30%	633	11%
Illinois	791	1,443	82%	1,231	56%
Indiana	635	1,032	63%	880	39%
Iowa	608	1,033	70%	882	45%
Kansas	609	1,032	69%	880	44%
Kentucky	584	959	64%	818	40%
Louisiana	391	704	80%	601	54%
Maine	1,018	2,772	172%	2,365	132%
Maryland	796	1,141	43%	974	22%
Massachusetts	1,060	1,520	43%	1,297	22%
Michigan	904	1,469	63%	1,254	39%
Minnesota	617	893	45%	762	23%
Mississippi	434	777	79%	663	53%
Missouri	756	1,269	68%	1,083	43%
Montana	600	881	47%	752	25%
Nebraska	538	1,000	86%	854	59%
Nevada	483	572	19%	488	1%
New Hampshire	892	1,251	40%	1,067	20%
New Jersey	805	1,138	41%	971	21%
New Mexico	512	690	35%	589	15%
New York	1,072	1,799	68%	1,535	43%
North Carolina	619	915	48%	780	26%
North Dakota	536	849	58%	724	35%
Ohio	772	1,168	51%	997	29%
Oklahoma	592	1,069	81%	912	54%
Oregon	713	792	11%	676	-5%
Pennsylvania	880	1,330	51%	1,135	29%
Rhode Island	1,004	1,358	35%	1,159	15%
South Carolina	529	793	50%	677	28%
South Dakota	530	833	57%	711	34%
Tennessee	502	827	65%	706	41%
Texas	415	728	75%	621	50%
Utah	616	882	43%	753	22%
Vermont	1,298	1,936	49%	1,652	27%
Virginia	761	972	28%	830	9%
Washington	881	916	4%	782	-11%
West Virginia	687	1,101	60%	940	37%
Wisconsin	634	859	36%	733	16%
Wyoming	620	1,002	62%	855	38%
United States	675	1,014	50%	865	28%

Total Power and Natural Gas Cost Increases

Combining the total increases in energy costs, U.S. consumers would pay over $284 billion ($173 billion) or 60% (37%) more for energy in 2020 under the 2020 CO_2 Case than they did in 2012. The states with the largest percentage increases in power and gas costs are Louisiana, Texas, Mississippi and North Dakota.

Electricity and Natural Gas Cost Increases ($BB): 2012 vs. 2020 CO_2 Case					
State	2012	2020	Increase	2020	Increase
Nominal Dollars				Real 2012 Dollars	
Alabama	9.4	14.6	56%	12.5	33%
Arizona	8.3	12.1	45%	10.3	24%
Arkansas	4.7	7.8	65%	6.7	41%
California	46.2	63.5	38%	54.2	17%
Colorado	6.8	11.2	65%	9.6	41%
Connecticut	5.8	9.0	56%	7.7	33%
Delaware	1.9	2.9	52%	2.4	30%
Florida	24.6	36.8	50%	31.4	28%
Georgia	15.0	22.6	51%	19.3	28%
Idaho	2.1	3.0	42%	2.6	21%
Illinois	18.3	33.3	82%	28.4	56%
Indiana	12.4	20.8	68%	17.8	44%
Iowa	5.2	9.9	90%	8.5	62%
Kansas	4.9	7.5	54%	6.4	31%
Kentucky	7.5	12.8	69%	10.9	44%
Louisiana	9.6	24.4	154%	20.8	117%
Maine	1.8	2.5	41%	2.2	20%
Maryland	8.6	13.4	55%	11.4	32%
Massachusetts	10.4	16.1	56%	13.8	33%
Michigan	17.0	27.5	62%	23.4	38%
Minnesota	8.2	12.6	54%	10.7	31%
Mississippi	5.0	9.8	96%	8.4	67%
Missouri	9.1	14.7	62%	12.5	38%
Montana	1.6	2.4	52%	2.1	29%
Nebraska	3.3	5.1	52%	4.3	30%
Nevada	3.8	6.0	56%	5.1	33%
New Hampshire	1.8	2.8	54%	2.4	32%
New Jersey	14.5	23.0	58%	19.6	35%
New Mexico	2.6	3.7	42%	3.1	21%
New York	29.0	43.8	51%	37.4	29%
North Carolina	13.4	19.0	41%	16.2	21%
North Dakota	1.4	2.9	107%	2.5	77%
Ohio	18.8	30.4	61%	26.0	38%
Oklahoma	6.7	11.2	68%	9.6	43%
Oregon	4.9	8.7	76%	7.4	50%

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Electricity and Natural Gas Cost Increases ($BB): 2012 vs. 2020 CO_2 Case					
State	**2012**	**2020**	**Increase**	**2020**	**Increase**
	Nominal Dollars			**Real 2012 Dollars**	
Pennsylvania	19.9	32.8	65%	28.0	41%
Rhode Island	1.4	2.3	58%	1.9	35%
South Carolina	7.9	11.3	43%	9.6	22%
South Dakota	1.4	1.9	41%	1.7	21%
Tennessee	10.4	15.3	47%	13.1	25%
Texas	39.3	81.8	108%	69.8	78%
Utah	3.3	4.9	50%	4.2	28%
Vermont	0.9	1.1	30%	1.0	11%
Virginia	11.6	16.6	43%	14.1	22%
Washington	8.6	11.2	30%	9.6	11%
West Virginia	3.0	4.3	42%	3.7	21%
Wisconsin	9.5	14.3	50%	12.2	28%
Wyoming	1.6	2.7	67%	2.3	43%
United States	**471**	**755**	**60%**	**644**	**37%**

Average household power and natural gas bills are projected to increase by $680/year ($293 in real dollars) from 2012 to almost $2,650/year ($2,260/year) in 2020 under the 2020 CO_2 Case, representing a 35% (15%) increase. States with the largest household percentage increases in combined power and natural gas bills are Texas, Illinois, Mississippi, Maine and Connecticut, with the largest of these being a 100% increase for Maine.

Average Annual Residential Electricity and Natural Gas Bill ($): 2012 vs. 2020 CO_2 Case					
State	**2012**	**2020**	**Increase**	**2020**	**Increase**
	Nominal Dollars			**Real 2012 Dollars**	
Alabama	2,218	3,020	36%	2,577	16%
Arizona	1,921	2,062	7%	1,759	-8%
Arkansas	1,821	2,720	49%	2,321	27%
California	1,488	1,737	17%	1,482	0%
Colorado	1,551	2,164	39%	1,847	19%
Connecticut	2,683	4,386	63%	3,743	40%
Delaware	2,409	3,078	28%	2,626	9%
Florida	1,871	2,336	25%	1,993	7%
Georgia	2,398	3,137	31%	2,677	12%
Idaho	1,598	1,890	18%	1,613	1%
Illinois	1,832	2,956	61%	2,523	38%
Indiana	1,866	2,647	42%	2,259	21%
Iowa	1,747	2,481	42%	2,117	21%
Kansas	1,865	2,619	40%	2,235	20%

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Average Annual Residential Electricity and Natural Gas Bill ($): 2012 vs. 2020 CO_2 Case					
State	2012	2020	Increase	2020	Increase
	Nominal Dollars			Real 2012 Dollars	
Kentucky	1,849	2,674	45%	2,281	23%
Louisiana	1,647	2,407	46%	2,054	25%
Maine	1,954	3,905	100%	3,332	70%
Maryland	2,345	3,242	38%	2,767	18%
Massachusetts	2,174	3,092	42%	2,638	21%
Michigan	2,049	3,014	47%	2,572	26%
Minnesota	1,705	2,180	28%	1,861	9%
Mississippi	1,901	3,098	63%	2,643	39%
Missouri	2,039	3,044	49%	2,597	27%
Montana	1,623	2,119	31%	1,808	11%
Nebraska	1,747	2,494	43%	2,128	22%
Nevada	1,809	2,062	14%	1,759	-3%
New Hampshire	2,082	2,964	42%	2,530	22%
New Jersey	2,141	3,015	41%	2,573	20%
New Mexico	1,414	1,723	22%	1,470	4%
New York	2,351	3,483	48%	2,972	26%
North Carolina	2,014	2,449	22%	2,090	4%
North Dakota	1,718	2,416	41%	2,062	20%
Ohio	2,022	2,874	42%	2,452	21%
Oklahoma	1,871	2,870	53%	2,449	31%
Oregon	1,843	2,378	29%	2,030	10%
Pennsylvania	2,165	3,170	46%	2,705	25%
Rhode Island	2,037	3,001	47%	2,561	26%
South Carolina	2,098	2,566	22%	2,190	4%
South Dakota	1,713	2,072	21%	1,768	3%
Tennessee	1,986	2,610	31%	2,228	12%
Texas	1,967	3,027	54%	2,583	31%
Utah	1,561	1,951	25%	1,665	7%
Vermont	2,467	3,348	36%	2,857	16%
Virginia	2,245	2,716	21%	2,318	3%
Washington	1,941	2,039	5%	1,740	-10%
West Virginia	1,960	2,710	38%	2,313	18%
Wisconsin	1,753	2,242	28%	1,914	9%
Wyoming	1,646	2,367	44%	2,020	23%
United States	1,963	2,643	35%	2,256	15%

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