CLIMATE CHANGE POLICY PARTNERSHIP

The Influence of Technology and a Carbon Cap on Natural Gas Markets

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Executive Summary

Background

Natural gas is used as a fuel to generate electricity, to heat and cool buildings, to run appliances, and to power vehicles. Natural gas is also a feedstock for many products and industries. Some observers speculate that natural gas demand and prices will increase under policies that restrict U.S. greenhouse gas (GHG) emissions as consumers switch from higher-carbon fuels like coal to lower-carbon natural gas. To estimate the impact of a national climate policy and changing market conditions, the Climate Change Policy Partnership (CCPP) at Duke University modeled ten natural gas market scenarios using the Energy Information Administration's (EIA) National Energy Modeling System (NEMS). The reference scenario and eight other primary scenarios[*] assume climate policy based on the Lieberman-Warner (S. 2191) Climate Security Act.[†] One business-as-usual scenario[‡] without a climate policy was run for comparison. The goal of this modeling project is to provide policy makers and natural gas market participants a comparison of natural gas market conditions under different technology scenarios with a carbon cap. The CCPP's modeling does not account for future environmental regulations other than a carbon cap, nor does it account for other barriers, such as transmission siting, that may affect future energy markets. Estimates of accessible unconventional natural gas reserves have increased substantially over the past year. The CCPP increased unconventional natural gas reserves relative to the EIA's Annual Energy Outlook 2008 to reflect this increase in supply but likely underestimated unconventional reserves based on new information available after the modeling was completed.

Principal Results

For all primary CCPP scenarios (including the reference scenario), S. 2191 climate legislation does not significantly increase U.S. natural gas demand, and coal electricity generation remains the primary baseload generation source in the United States. Under S. 2191 climate legislation, natural gas and electricity prices are highly dependent on the rate of low-carbon electricity generation technology development.

Natural Gas Prices

Differing rates of development for new electricity generation technologies—such as wind turbines, biomass power plants, and integrated gasification combined cycle (IGCC) coal plants with carbon capture and storage (CCS)—significantly affect natural gas markets. The average price utilities pay for natural gas, which includes the cost of carbon, steadily increases in the reference case from $8 per MMBtu[§] in 2008 to about $13 per MMBtu in 2030. When the development of new electricity

[*] The reference scenario is a primary scenario. All nine primary scenarios include a carbon cap based on S. 2191.

[†] The CCPP uses S. 2191 for its analysis rather than S. 3036, the bill voted on by the full Senate, because EIA created a scenario in NEMS to model the effects of S. 2191 on U.S. energy markets.

[‡] The business as usual scenario is *not* a primary scenario.

[§] MMBtu = million Btu.

technologies is limited, natural gas prices are 20% higher in 2030 than in the reference scenario. When new electricity technologies develop rapidly, natural gas prices are 9% lower in 2030 than in the reference scenario. Changes in the development of natural gas extraction technologies have little influence on natural gas prices. The CCPP modeled natural gas markets prior to the 2008 financial crisis and decline in natural gas prices. See the full report for further discussion of current market conditions.

Natural Gas Demand

Despite the constraint of a carbon cap, natural gas demand in the reference scenario is relatively constant, around 23 to 24 trillion cubic feet (Tcf) per year through 2030. With the exception of one scenario after 2026, natural gas demand remains below 25 Tcf per year for all scenarios.

Electricity Generating Capacity

The model projects that coal-fired electricity generation capacity under the reference scenario increases slightly and then declines 17% from 317 gigawatts (GW) in 2013 to 262 GW in 2030. Coal capacity follows a similar pattern in the other primary scenarios. Reference scenario natural gas generation capacity decreases sharply in 2012 from about 450 GW to about 400 GW and then remains relatively constant, whereas renewable generation capacity more than doubles from 106 gigawatts (GW) in 2008 to 233 GW in 2030. For all other scenarios, the amount of new natural gas capacity and new renewable generation capacity are substitutes for one another; i.e., rapid development of renewable energy technologies and renewable capacity results in less new natural gas capacity, while slow development of renewables results in more new natural gas capacity.

Electricity Generation

Natural gas and renewable generation are substitutes for one another, but they are not substitutes for coal baseload generation. Under all primary scenarios, total electricity generation is roughly constant or increases slightly through 2030. Coal-based electricity generation steadily declines in all primary scenarios from about 2,000 terawatt hours (TWh) in 2008 to around 1,400 TWh in 2030 but remains the largest source of baseload electricity generation in the U.S. As with generation capacity, natural gas and renewable electricity generation vary significantly depending on the rate of electricity generation technology development. The model projects that reference scenario natural gas generation increases from 699 TWh in 2008 to 836 TWh in 2030, while renewable generation increases from 360 to 1,188 TWh (2008–2030). For all scenarios, coal capacity factors—the percent of time a plant runs over the course of a year—are at least double natural gas capacity factors. Nuclear generation is approximately constant through 2030 for all technology cases as no new nuclear plants are built in any CCPP scenarios because of high construction cost assumptions.

Electricity Prices

Average electricity prices increase from 9 cents per kWh in 2008 to 14.5 cents per kWh in 2030 under the reference scenario. Restricting or slowing development of low-carbon electricity technology leads to average electricity prices ranging from 12% to 25% higher than the reference scenario in 2030. Not surprisingly, when low-carbon electricity technology develops rapidly, average electricity prices drop relative to the reference scenario.

GHG Allowance Prices

GHG emission allowance prices are consistent for all primary scenarios except when CCS retrofits are not allowed. The model projects that reference scenario allowance prices start at $26 per ton of CO_2 in 2008 and rise to $83 per ton in 2030.[*] The inability to retrofit existing power plants increases allowance prices 55% compared to the reference case. Based on the CCPP's modeling, CCS retrofits are a critical technology to control costs under a carbon cap.

Relative Fuel Costs

Even after factoring in the cost of allowances, *coal is cheaper than natural gas on a Btu basis in all years and for all scenarios.* This result further explains why natural gas does not displace coal as the primary baseload generation fuel in the United States under S. 2191 or a similar carbon cap. Despite the significant drop in natural gas spot market prices over the last six months, natural gas prices are still 70% higher than the average coal prices paid by electric utilities.[†]

Policy Implications

If policymakers are concerned about the impact of climate change legislation on future natural gas prices, CCPP suggests that policymakers invest in low-carbon electricity technology, such as renewable generation and CCS retrofits, as a hedge against future high natural gas prices.

[*] The magnitude of allowance prices is greatly influenced by updated electricity generating technology cost assumptions as detailed in the full report

[†] Based on comparison of Henry Hub spot market price for natural gas on 4/2/09 ($3.70 per mmBtu, Bloomberg http://www.bloomberg.com/markets/commodities/energyprices.html) and the average price utilities paid for coal in December 2008, the most recent average cost data available from EIA ($2.16 per mmBtu http://www.eia.doe.gov/cneaf/electricity/epm/table4_1.html). Based on regional coal spot price data (http://www.eia.doe.gov/cneaf/coal/page/coalnews/coalmar.html#spot) variable operating costs for natural gas combined cycle plants are likely lower than variable operating costs for pulverized coal plants in select areas of the United States as of April 3, 2009.

1. Introduction

Natural gas is an important fuel for the United States and provides over 22% of the nation's primary energy supply.[1] Americans rely on natural gas to provide heating and cooling for buildings and factories, to generate electricity, and as a feedstock for producing many goods and services. In 2006, the electricity sector represented 30% of U.S. natural gas demand, industry 34%, and the commercial and residential sectors 33%.[2] Changing political and economic conditions in energy markets within the next 10 to 15 years may have a profound impact on natural gas prices and availability in the U.S. Some observers speculate that demand for natural gas may increase with the adoption of policies that cap U.S. greenhouse gas (GHG) emissions, as consumers may switch to natural gas from dirtier fossil fuels like coal and oil. The development of utility-scale, low-carbon electricity generation technologies such as wind and solar may progress slowly and further buoy demand for natural gas. Supply of natural gas needs to keep pace with growing demand in order to prevent an increase in natural gas prices.

The Climate Change Policy Partnership (CCPP) at Duke University forecasted ten energy market scenarios to study potential natural gas price paths, resource flows, and industry interactions under a federal GHG cap-and-trade policy regime. The CCPP used the 2008 version of the Energy Information Administration's (EIA) National Energy Modeling System (NEMS) to forecast future conditions.

2. Background

2.1. Overview of the North American natural gas market

Unlike oil, the United States produces most of the natural gas it consumes. In 2007, the United States produced 83% of its natural gas supply. Pipeline imports—primarily from Canada—provided 13% of the nation's supply and the remainder (~3%) came from liquefied natural gas (LNG) imports.[3] There are concerns about the sustainability of Canadian natural gas imports as Canada's domestic demand increases and conventional natural gas supplies in Canada decline. Canadian oil sands extraction requires massive inputs of heat and may reduce the amount of natural gas available for export to the United States. The EIA projects that Canadian gas imports will significantly decrease over the next 30 years.[4]

The North American natural gas market relies on a vast pipeline network to deliver gas from producers to consumers. Within the United States, natural gas is produced in many areas of the country, including New Mexico, Wyoming, Louisiana, Texas, and Oklahoma, as well as offshore in the Gulf of Mexico. The U.S. natural gas pipeline system is highly integrated with the Canadian natural gas pipeline system. Within the lower 48 states and parts of Canada, conventional natural gas supplies are mature and in decline.[16,17]

Global LNG Trade

LNG trade began in the 1970s, enabling intercontinental natural gas trade. Prior to the development of LNG technology, natural gas trade was restricted to regional pipeline networks. LNG trade requires massive capital investments for liquefying, regasifying, and shipping LNG. Because of high capital costs, LNG is a marginal supply in many parts of the world with adequate local supplies and transportation infrastructure.

Global LNG trade is generally analyzed in the two major consuming regions, the Pacific and Atlantic basins. The two regions contrast starkly through pricing schemes and demand elasticity. The Pacific region is dominated by long-term contracts indexed to oil prices. Spot trading in the Pacific region is minimal compared to the Atlantic. Many Pacific nations, especially Japan and South Korea, lack domestic energy resources and natural gas storage infrastructure, necessitating continuous LNG shipments to keep power plants running. Together, Japan and South Korea account for 55% of global LNG demand,[5] and LNG represents 90% of the natural gas supply to those countries.[6] Due to inelastic demand for many nations in the Pacific region, recent LNG prices paid in the Pacific region have been twice Henry Hub* prices in the United States.[7] There is currently one regasification terminal in operation on the Pacific coast of North America in Costa Azul Mexico.[8] All other operating natural gas regasification terminals in North America are located in the Atlantic region (including the Gulf of Mexico). The Atlantic basin market is dominated by short-term contracts and spot transactions. Flows in the Atlantic basin appear to be based on economic preferences of LNG exporters, who are not bound by the same long-term contracts as exporters in the Pacific basin. If spot prices in Europe are sufficiently higher than spot prices in North America, LNG cargoes originally destined for North America are often rerouted to Europe or vice-versa.

Worldwide, there is a 2:1 ratio of regasification capacity to liquefaction capacity.[9] The excess capacity of regasification facilities compared to liquefaction facilities has created a sellers' market, enabling LNG exporters to sell their LNG to the highest bidders. Global liquefaction capacity is expected to grow significantly over the next 20 years, but there is considerable uncertainty about the level of growth and whether significant supplies will be available in North America.[10] A recent report by the American Gas Foundation projects that significant LNG supplies will be available to the United States in the medium- to long-term (10–15 years),[11] but prior estimates of liquefaction growth have proven to be overly optimistic.[12] Russia, Iran, and Qatar, countries with the largest known natural gas reserves in the world, are openly discussing forming a natural gas cartel similar to OPEC to attempt to control global natural gas prices.[13] Most analysts believe that a natural gas export cartel would not be effective at controlling prices in most regions in the near term as the global natural gas market is still highly fragmented.[14,15]

[*] The Henry Hub, located in Louisiana, connects nine interstate and intrastate pipelines and is considered the United States' natural gas price benchmark.

The lower 48 states contain significant reserves of unconventional natural gas, including coal bed methane, tight sands, and gas shales. Multiple companies have recently announced successful drilling of previously inaccessible unconventional natural gas supplies in the lower 48 states including Fayetteville Shale, Haynesville Shale, and Marcellus Shale.[18] There have also been recent announcements of successful drilling of new shale gas formations* in Canada.[19] Production of unconventional natural gas has increased as a share of total production in the continental United States, rising from 16% in 1990 to 41% in 2004.[20] Given the large increase in accessible unconventional natural gas resources, natural gas production in North America should continue to increase in the future so long as production from unconventional resources remains economically feasible.

Liquefied natural gas (LNG) is a significant energy source for many areas of the world but remains a marginal natural gas source in North America. LNG trade requires massive capital investments for liquefying, regasifying, and shipping LNG. The liquefying, regasifying and shipping of LNG is also energy intensive and results in high greenhouse gas (GHG) emissions relative to domestic natural gas transported through pipelines. When used for electricity generation in the United States, LNG has on average 28% higher lifecycle GHG emissions per megawatt hour of electricity generated than domestic natural gas.[21] LNG is a global commodity and the United States must compete with other LNG buyers to purchase LNG cargos.† 2008 U.S. LNG imports were significantly lower than 2004–2007 imports as higher prices in other markets like East Asia and Europe drew supplies away from the U.S. market.[22,23] Future LNG prices and availability to North American markets is largely unknown and will depend on future liquefaction capacity growth, LNG demand growth outside the United States and other geopolitical factors.

2.2. Alternative natural gas sources, substitutes, and demand sources

Prior to the development of natural gas infrastructure, synthetic gas made from coal was used for heating, cooking, and lighting. There is currently one commercial scale plant in the United States producing about 54 billion ft^3/year‡ of natural gas from coal and multiple companies have proposed building additional plants.[24,25] Methane produced from decaying matter in landfills and other biogases are other potential substitutes for natural gas.§ Despite the opportunity for significant growth, potential landfill gas and biogas resources are limited and therefore could only substitute for a small percentage of total natural gas supply.[26,27]

* Natural gas formations are often referred to as natural gas plays.

† Regional natural gas markets, such as the North American natural gas market, are generally disconnected from prices in other markets so long as the majority of supplies are from non-LNG sources.

‡ 54 billion ft^3/year represents less than 0.3% of 2007 U.S. natural gas demand.

§ 2006 U.S. landfill gas consumption totaled the equivalent of 145 MMcf of natural gas – EIA. 2006. *Table 1.7 Waste Energy Consumption by Type of Waste and Energy Use Sector, 2006*. Energy Information Administration. Retrieved on June 24, 2008 from http://www.eia.doe.gov/cneaf/solar.renewables/page/landfillgas/landfillgas.html

Natural gas can also be used to produce liquid petroleum fuels in gas-to-liquids plants. However, current gas-to-liquids natural gas consumption is low, approximately 0.3 Tcf in 2004,[28] but could grow significantly depending on future world oil prices and demand for petroleum fuels.

2.3. Other U.S. natural gas supply and demand estimates

The federal government and numerous other institutions have published estimates of future domestic natural gas production, demand, and import availability. Most published estimates do not account for recent successful drilling of major unconventional natural gas resources in North America and do not include a federal carbon cap or tax. A summary of three recent natural gas market modeling reports, including the EIA's Annual Energy Outlook 2008 and a LNG supply paper are included in Appendix C.[*] All of the natural gas modeling reports project that domestic natural gas production will increase and LNG imports will more than double over the next 20 to 30 years as Canadian imports decline. Two of the natural gas modeling reports project that natural gas demand will increase steadily through 2030 while the Annual Energy Outlook 2008 projects natural gas demand will increase until around 2020 and then decline below current demand levels by 2030. Due to the large uncertainty about future LNG availability, the CCPP restricts LNG imports. Please refer to section 3.2, page 12, for further explanation.

[*] The EIA released the *Annual Energy Outlook 2009 Early Release* in January 2009. The full report was not available when this paper was made public.

3. Methodology, Assumptions, and Scenarios

The CCPP modeled the U.S. energy system using Duke University's Nicholas Institute for Environmental Policy Solutions version of the National Energy Modeling System (NI-NEMS) to estimate the impacts of a cap-and-trade policy on natural gas supply and availability under a variety of market conditions. Through its modeling efforts, the CCPP is providing a range of natural gas and electricity sector forecast data for a variety of natural gas and electricity sector scenarios under the Lieberman-Warner Climate Security Act (S. 2191), a GHG cap-and-trade bill considered by the U.S. Senate in June 2008.[*]

The federal government developed NEMS in the late 1980s and has since used the model for official government energy forecasts and policy analysis. NI-NEMS is a bottom-up engineering-economic model that represents all major energy producing and consuming sectors of the U.S. economy.[†] NI-NEMS finds prices that equilibrate supply and demand for fuels and energy services. In this sense, prices are endogenous (i.e., the model determines prices). NI-NEMS also simulates investment and operation decisions into the future based on expected growth in demand and available technology options. By integrating technology simulation with economic market equilibration, NI-NEMS can serve as a forecasting tool as well as a policy analysis model. NI-NEMS outputs provide detailed information on all sectors of the U.S. energy system, including fuel prices, electricity generation type, and fuel consumption. Through scenario analysis, users can learn about the market interactions between different fuels and consuming sectors' changing conditions. Therefore, the CCPP can adjust NI-NEMS inputs to forecast U.S. energy markets under climate policy for a range of potential market conditions.

To model natural gas conditions, the CCPP focused on supply-side energy market conditions due to the innate transparency and easy manipulation of such conditions in the model, rather than the ambiguity of demand elasticities. Prior to conducting modeling, the CCPP reviewed reports on the availability of domestic natural gas reserves, availability and fundamentals of natural gas imports, and the economic and political risks potentially affecting natural gas supplies. Based on CCPP's review of other natural gas studies, consultation with the CCPP's corporate partners,[‡] and news reports on the natural gas industry, the CCPP updated estimates of domestic natural gas reserves and restricted LNG supplies to reflect the considerable uncertainty about future LNG availability in the United States. The CCPP then formulated natural gas supply-side scenarios in which assumptions about the cost of extraction vary and demand-side scenarios in which assumptions about the availability and development of electricity technologies vary.

Additionally, the CCPP updated EIA's assumptions regarding new electricity-generating technologies to reflect recent increases in material prices (e.g., steel and concrete) and a shortage of skilled labor

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[*] The CCPP used S. 2191, rather than the version introduced to the Senate (S. 3036), because the EIA created this scenario for NEMS to model the effects of S. 2191 on U.S. energy markets.

[†] NI-NEMS assumes a real GDP growth rate of 2.4% per year. The ongoing financial crisis and U.S. recession have reduced near-term energy consumption and prices. This near-term drop in U.S. energy demand and prices is not reflected in the model.

[‡] Current corporate partners include ConocoPhillips, Duke Energy, and MeadWestvaco.

needed for power plant construction. Together, these factors have driven new plant costs up dramatically in the last few years. Note that NI-NEMS does not account for potential new environmental regulations, such as stricter mercury emissions regulations, or policy barriers, like siting new electricity transmission lines, that might affect future energy markets.

3.1. Lieberman-Warner Climate Security Act scenario (S. 2191 scenario)

The CCPP analysis starts with the S. 2191 scenario that the EIA created for NEMS. This scenario attempts to reflect both the mandates and options for flexibility as outlined in S. 2191, including emissions trading, banking, and offsets. Although CCPP scenarios include S. 2191 assumptions about the emissions cap level, sector participation, and flexibility mechanisms, we recognize that federal climate legislation, if passed, will almost certainly differ in details. Nevertheless, S. 2191 creates a carbon cap and an emissions trading mechanism that introduces a price signal to U.S. energy markets that any federal climate legislation limiting GHG emissions would create.

3.2. CCPP Assumptions that diverge from EIA

The CCPP analysis increases the unconventional natural gas reserve base to reflect recent unconventional gas discoveries and successful drilling of new unconventional resources such as the Haynesville Shale formation. Chesapeake Energy recently announced successful drilling in the Haynesville Shale in Louisiana and East Texas, but the Haynesville Shale is not included in the 2008 NEMS unconventional natural gas resource base.[29] Despite increasing unconventional natural gas reserves relative to the Annual Energy Outlook 2008, the CCPP likely underestimated unconventional reserves based on new information available after the modeling was completed.[*]

The CCPP analysis restricts LNG imports to reflect considerable uncertainty in future LNG imports. For 2008 and 2009, the CCPP restricted LNG import levels based upon the EIA's short-term energy outlook. Beyond 2009, LNG imports were allowed to increase between 20 to 40 billion cubic feet (Bcf) per year until 2030. The CCPP was intentionally conservative in its estimates for future LNG imports because NI-NEMS does not consider geopolitical factors when making projections. NI-NEMS is an economic model and assumes that if resources are available for development and market prices are high enough, the resource will be developed.[†] In reality, many large-scale energy projects that should be cost-effective are not built because of geopolitical factors such as national governments' restrictions on foreign investment or political instability. Capping future LNG imports to the United States ensures that NI-NEMS will not overestimate future natural gas supplies based on potential LNG imports. Natural gas

[*] A recent report by Cambridge Energy Research Associates reports that North American natural gas supplies are no longer constrained and can meet demand through at least 2018 (http://www.cera.com/aspx/cda/public1/news/pressReleases/pressReleaseDetails.aspx?CID=10179). The Annual Energy Outlook 2009 includes both the Haynesville and Marcellus shale resources, more than doubling shale resources compared to the Annual Energy Outlook 2008 (interview with Dana Van Wagener of EIA on 2/24/09). The CCPP increased shale supplies to reflect the Haynesville shale but not the Marcellus or Fayetteville shales.

[†] NI-NEMS only assumes that resources designated by governments as available for future development may be developed. NI-NEMS does not assume that a restricted resource, for example in a nature preserve, is available for development.

liquefaction and regasification facilities require large, long-term capital investments and future LNG availability in the United States will largely depend on liquefaction capacity growth and demand in other countries, especially in Asia and Europe. The current financial uncertainties and the potential natural gas demand growth in developing countries reinforce the CCPP's conservative estimates of future LNG availability for this modeling exercise.

If the U.S. government establishes a mandatory GHG cap-and-trade system, carbon capture and storage (CCS) technologies are expected to play a major role in reducing GHG emissions from the electricity sector. The EIA's version of NEMS restricts carbon capture technology to new natural gas combined cycle and new integrated gasification combined cycle coal power plants. Retrofitting existing power plants to capture GHG emissions is another promising mitigation option, however. Utilities have already made major investments in existing natural gas and coal power plants and it may be less expensive to retrofit an existing plant with CCS technology to capture and sequester GHG emissions than to build a new power plant with CCS technology. The Department of Energy's (DOE) National Energy Technology Laboratory has created an add-on for NEMS to allow existing power plants to retrofit with CCS technologies.[30] CCPP used this add-on in NI-NEMS for its scenarios but revised the retrofit cost assumptions to be consistent with updated power plant cost assumptions as noted below.

Many of EIA's cost estimates for constructing new electricity generation capacity are out of date. Over the past few years, new generation construction costs increased significantly as materials costs and certain labor costs rose. The CCPP updated EIA's estimates for overnight construction costs—the total cost of building new generation capacity, excluding financing costs—based on an extensive literature review and consultation with the CCPP's corporate partners. The CCPP's updated overnight cost estimates are higher than EIA's estimates for all generation sources and significantly higher for new nuclear capacity (a 99% increase), integrated gasification combined cycle (IGCC) with CCS (a 31% increase), and advanced combustion turbines (a 68% increase). See Table 17a in Appendix A for a complete comparison of EIA AEO 2008 and CCPP Natural Gas Project overnight construction cost estimates.

3.3. EIA analysis of S. 2191

At the request of members of Congress, EIA estimated the impacts on S. 2191 using its NEMS model. The report on the modeling results, *Energy Market and Economic Impacts of S. 2191, the Lieberman-Warner Climate Security Act of 2007,* was released in April 2008.[31] The model uses the assumptions of the Annual Energy Outlook 2008 (AEO 2008) as a baseline. CCPP modeling results are significantly different than EIA's, especially for coal and nuclear electricity generation, because EIA does not allow for CCS retrofits of existing power plants and does not include CCPP's updated assumptions for new generation construction costs, unconventional natural gas resources, and LNG import availability.

3.4. CCPP scenarios

The CCPP created ten scenarios, one scenario without S. 2191 climate change legislation and nine primary scenarios including the S. 2191 cap-and-trade system. All scenarios include the baseline changes in unconventional natural gas resources, limits on LNG imports, and overnight construction costs described above. The scenarios capture the full range of natural gas extraction technology development and the full range of technology development within the electricity sector. Natural gas extraction technology development and electricity sector technology development refer to the rates at which these two sectors improve and reduce costs because of innovation and operating experience.

Scenario 1: Business-as-usual (BAU) - no carbon cap

Scenario 2: Reference S. 2191 scenario

Scenario 3: High natural gas extraction technology development with S. 2191

Scenario 4: High natural gas extraction technology development and high electricity-sector technology development with S. 2191

Scenario 5: High natural gas extraction technology development and low electricity-sector technology development with S. 2191

Scenario 6: Low natural gas extraction technology development with S. 2191

Scenario 7: Low natural gas extraction technology development and high electricity-sector technology development with S. 2191

Scenario 8: Low natural gas extraction technology development and low electricity-sector technology development with S. 2191

Scenario 9: Restricted technology scenario – low natural gas extraction technology development, low electricity-sector technology development, no new nuclear plants until 2020, no new coal plants or natural gas plants with CCS until 2020, with S. 2191[*]

Scenario 9b: Restricted technology scenario b – no retrofitting of existing power plants with CCS throughout the modeling period, low natural gas extraction technology development, low electricity-sector technology development, no new nuclear plants until 2020, no new coal plants or natural gas plants with CCS until 2020, with S. 2191[†]

[*] New coal and natural gas plants without CCS are possible before 2020 in scenario 9a.
[†] New coal and natural gas plants without CCS are possible before 2020 in scenario 9b.

Figure 1. CCPP scenarios in a natural gas extraction and electricity sector technology matrix. Business as usual scenario 1 (not shown) has same technology assumptions as reference scenario 2, but without a carbon cap.

	High NG Extract Tech	Ref NG Extract Tech	Low NG Extract Tech
High Elec Tech	4		7
Ref Elec Tech	3	2	6
Low Elec Tech	5		8
Low Elec Tech, No CCS or Nuc until 2020			9
Low Elec Tech, No Retro CCS ever, No CCS or Nuc 2020			9b

The CCPP included restricted technology scenarios to model energy markets if multiple technologies fail to develop as anticipated. For example, new nuclear power plants require large capital investments, must undergo a lengthy permitting process, and may face political hurdles. Consequently, it is quite possible that no new nuclear power plants will be built in the next 10 to 15 years. CCS also faces numerous obstacles. No full-scale power plants with CCS are currently operating in any country and the true costs of CCS are unknown. The CCPP makes no judgment about the likelihood of any of its scenarios occurring and only seeks to present a range of forecasts that allow readers to draw their own conclusions about the likelihood of each scenario. For a discussion of barriers to new generation technologies including CCS, wind, and biomass, see the CCPP's *A Convenient Guide to Climate Change Policy and Technology*[*] and *Wind Power: Barriers and Policy Solutions*.[†]

3.5. Natural gas extraction technology development adjustment

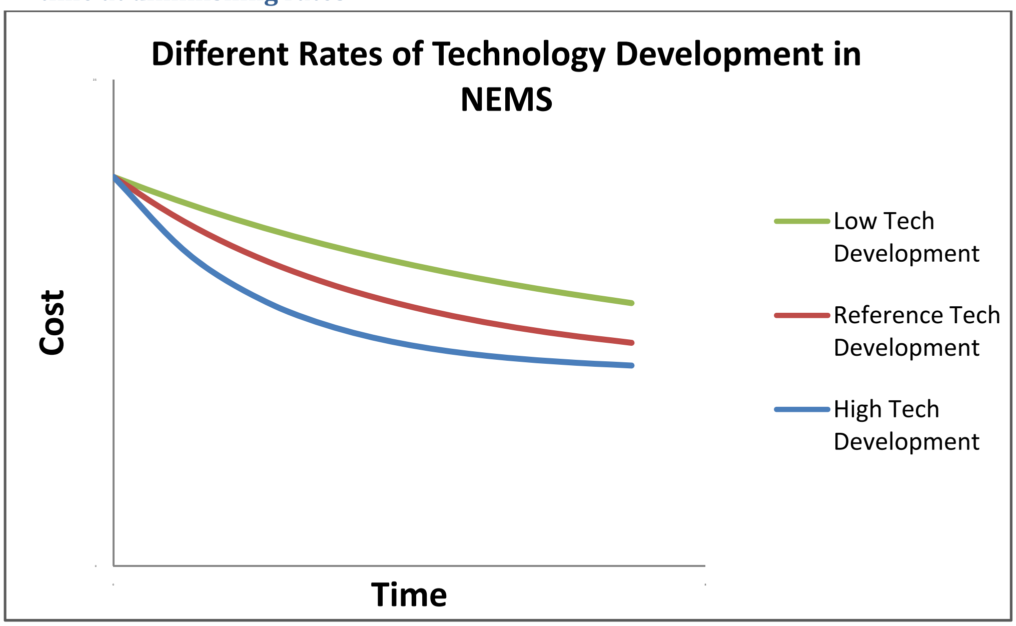
To adjust natural gas extraction technology development, the CCPP adjusted annual improvement rates for drilling costs, lease equipment costs, operating costs, finding rates, success rates, facility construction costs, and initial production rates. Additionally, the CCPP adjusted the availability and development of unconventional production technology for the high and low natural gas technology development scenarios. Adjusting these natural gas sector inputs effectively reduces or increases future natural gas extraction costs and reduces or increases the percentage of natural gas extracted from available natural gas resources where drilling occurs relative to the reference scenario. The ability to extract natural gas from conventional and unconventional resources does not become worse in the low natural gas sector technology development scenarios; it improves at slower rates than the reference and high scenarios natural gas sector technology development scenarios (see Figure 2, below).

[*] Available from http://www.nicholas.duke.edu/ccpp/convenientguide/index.html
[†] Available from http://www.nicholas.duke.edu/ccpp/publications.html

3.6. Electricity sector technology development adjustment

To adjust rates of electricity sector technology development, the CCPP adjusted overnight construction costs, technology optimism factors,* and learning factors for the high and low electricity-sector technology development scenarios. CCS technology development is affected by these input adjustments. Adjusting technology inputs effectively increases or decreases the future cost of constructing new and emerging generation technologies and speeds up or slows down their development. Mature generation technologies are largely unaffected by technology development factors. Figure 2, below, gives a visual representation of different rates of technology development in NI-NEMS. See Appendix B for a full explanation of CCPP natural gas extraction and electricity sector assumptions.

Figure 2. Illustrative graphical example of different rates of technology development in NI-NEMS. NI-NEMS assumes all technologies improve over time at diminishing rates.



* Technology optimism factors measure the tendency of markets to underestimate the true cost of a new technology.

4. Modeling Results and Discussion

4.1. Results and discussion summary

Differing rates of development for low-carbon electricity generation technologies significantly affect natural prices and electricity sector natural gas demand. Reference scenario delivered industrial and electricity sector natural gas prices, including the cost of carbon, increase from about $7.5 per thousand cubic feet in 2008 to $13 per thousand cubic feet in 2030. Low electricity generation technology development increases delivered prices up to 25% relative to the reference case and even higher for restricted CCS retrofits. Natural gas demand decreases under a carbon cap relative to the scenario without a cap and remains relatively constant, around 23 to 24 Tcf per year through 2030. Non-electricity sector natural gas demand stays more or less constant under a carbon cap, whereas electricity sector natural gas demand varies significantly depending on technology development.

Varying rates of electricity sector development also significantly impact electricity prices and generation. Coal generation capacity increases slightly through 2012 and then declines 17% from about 315 GW in 2013 to about 260 GW in 2030. High electricity-sector technology development, with rapidly improving CCS technology, increases coal capacity over 10% relative to the reference scenario in 2030. Natural gas capacity falls in 2012 from around 440 GW, as older generation capacity is retired, to about 400 GW and remains relatively constant for most primary* scenarios until 2030. Natural gas capacity increases, after 2025, for scenarios with low electricity-sector technology development to approximately 470 GW in 2030. With the exception of low electricity-sector technology development scenarios, renewable capacity more than doubles from 106 GW to more than 200 GW in 2030 for all primary scenarios.

Coal-fired electricity generation steadily declines under a carbon cap from about 2,000 TWh in 2008 to around 1,400 TWh in 2030, but remains the primary baseload generation source in the United States. For CCPP's scenarios, natural gas is not a substitute for coal baseload generation under an S. 2191 or similar carbon cap. Average coal capacity factors—the percent of time a plant runs over the course of a year—remain at least twice as high as average natural gas capacity factors, and fuel and variable operating costs are lower for coal than for natural gas combined cycle generation plants in most years. New natural gas and renewable generation capacity are substitutes for one another and vary significantly depending on technology development. Reference scenario renewable generation increases over 200% from 360 TWh in 2008 to about 1,200 TWh in 2030, while reference scenario natural gas generation increases 20% from 699 TWh in 2008 to over 800 TWh in 2030. For all other primary scenarios, if natural gas generation increases relative to the reference scenario, renewable generation decreases and vice versa. Reference scenario average electricity prices increase from 9 cents/kWh in 2008 to 14 cents/kWh in 2030 with higher prices for low electricity-sector technology development scenarios. Reference scenario GHG emissions allowance prices increase from $23 in 2012, the first year of a carbon cap with S. 2191, to $83 in 2030. Allowance prices for other primary scenarios are similar

* Primary scenarios are all scenarios with a carbon cap. Nine of the ten CCPP scenarios are primary scenarios.

except for the most restricted scenario that does not allow CCS retrofits. The inability to retrofit existing plants with CCS increases allowances prices 55% relative to reference scenario prices.

Technology development, especially the development of low-carbon electricity generation technologies, is key to controlling delivered natural gas and electricity prices under a carbon cap. If federal policymakers are concerned about the impacts of a carbon cap on natural gas prices, CCPP modeling results suggests that policymakers should invest in electricity sector technology, especially renewables, CCS, and CCS retrofit technology, as a hedge against high future natural gas and electricity prices.

5. Natural Gas Markets Results

5.1. Henry Hub prices

For each scenario, NI-NEMS projects that average annual Henry Hub prices will decline to about $6 per MMBtu (2006 dollars) around 2014 and remain between $6 and $7 per MMBtu until 2022 (Figure 3). The price decline is likely due to an increase in the availability of unconventional natural gas reserves. Henry Hub prices increase beyond 2022 for all scenarios. The magnitudes of the price increases are dependent upon the respective scenario's assumptions about natural gas and electricity sector technology development. The largest impact on Henry Hub prices is from differing levels of electricity sector technology development and restrictions on CCS and CCS retrofits. For scenarios with low technology development in the natural gas extraction and electricity sectors (scenarios 8, 9, and 9b), prices exceed $10/MMBtu in 2030, likely because of fewer generation alternatives and higher natural gas extraction costs relative to other scenarios. For all other scenarios, Henry Hub prices remain below $9/MMBtu through 2030. The model projects that for most years, a carbon cap (reference scenario 2) lowers the price of natural gas, excluding the cost of carbon, relative to the scenario without a cap. This occurs because a carbon cap creates a cost for carbon, effectively adding a tax to the Henry Hub price and, thus, decreasing demand for natural gas.[*] Please note that Henry Hub prices are average annual prices and that NI-NEMS does not account for potential exogenous shocks, such as hurricanes, that may temporarily affect natural gas prices.

The ongoing financial crisis has reduced the cost of all fossil fuels including natural gas. For example, NYMEX natural gas spot market prices dropped over 40% from October 3, 2008 to March 6, 2009.[32] Industrial demand for natural gas, the least temperature dependent demand source, was 10% lower in December 2008 than December 2007.[33] Despite the significant drop in natural gas spot market prices over the last six months, natural gas prices are still 70% higher than the average coal prices paid by electric utilities.[†] A sustained drop in natural gas prices, relative to other fuels, would encourage fuel substitution with natural gas where cost effective, potentially increasing natural gas demand.[‡] Future industrial natural gas demand will also play a large role in determining natural gas prices.

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[*] NI-NEMS projects that Henry Hub prices are higher for scenario 2 (reference Lieberman-Warner scenario) than scenario 1 (no carbon cap scenario) in 2017–2020. For all other years after 2007, prices are higher in scenario 1.

[†] Based on comparison of Henry Hub spot market price for natural gas on 4/2/09 ($3.70 per mmBtu, Bloomberg http://www.bloomberg.com/markets/commodities/energyprices.html) and the average price utilities paid for coal in December 2008, the most recent average cost data available from EIA ($2.16 per mmBtu http://www.eia.doe.gov/cneaf/electricity/epm/table4_1.html).

[‡] Based on regional coal spot price data (http://www.eia.doe.gov/cneaf/coal/page/coalnews/coalmar.html#spot) variable operating costs for natural gas combined cycle plants are likely lower than variable operating costs for pulverized coal plants in select areas of the United States as of April 3, 2009.

Figure 3. Average annual Henry Hub prices. Prices do not include the cost of carbon.

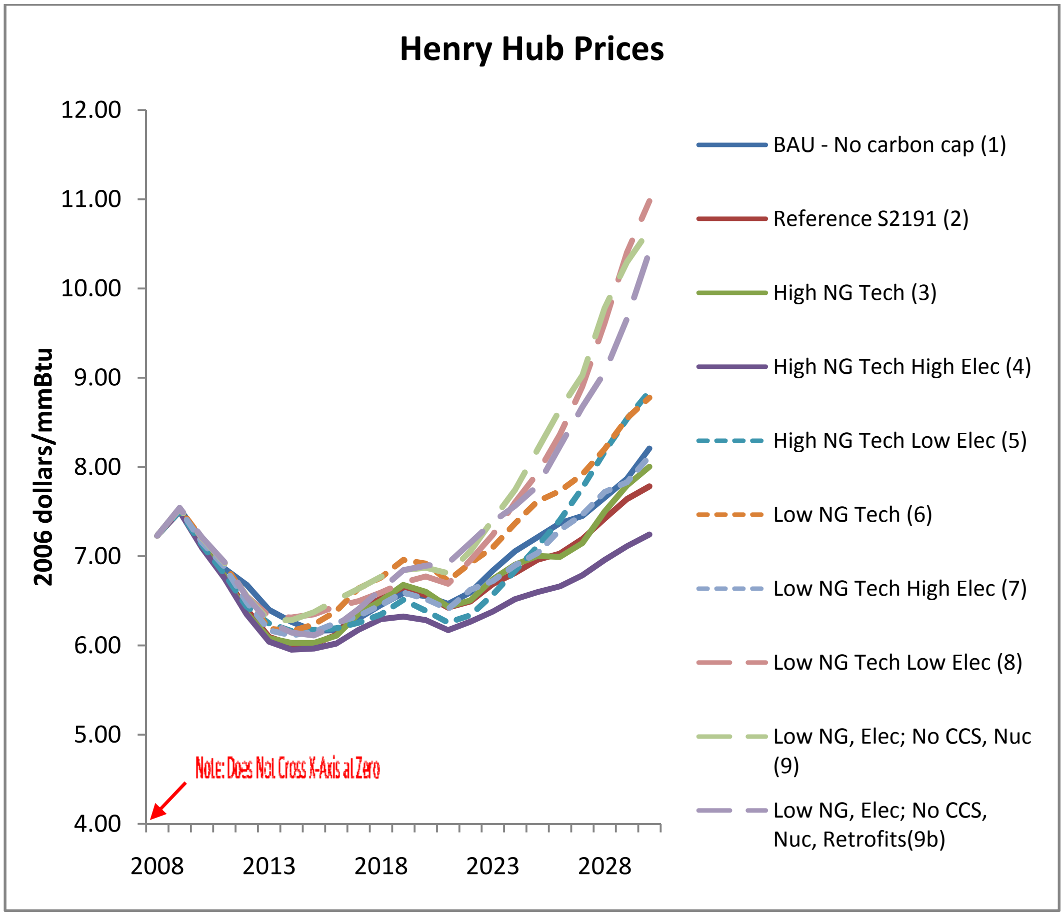


Table 1. Percent change in Henry Hub Price from reference scenario.

	2008	2010	2015	2020	2025	2030
Business-as-usual - No carbon cap (1)	0%	1%	2%	0%	4%	5%
Reference S. 2191 (2)	7.23	7.13	6.02	6.56	6.96	7.78
High NG Tech (3)	0%	0%	0%	1%	1%	3%
High NG Tech High Elec (4)	0%	-1%	-1%	-4%	-5%	-7%
High NG Tech Low Elec (5)	0%	0%	3%	-3%	2%	14%
Low NG Tech (6)	0%	1%	4%	5%	9%	13%
Low NG Tech High Elec (7)	0%	0%	2%	-1%	1%	4%
Low NG Tech Low Elec (8)	0%	1%	6%	3%	14%	41%
Low NG, Elec; No CCS, Nuc (9)	0%	1%	6%	5%	18%	37%
Low NG, Elec; No CCS, Nuc, Retrofit(9b)	0%	1%	2%	5%	12%	34%

Percent change in Henry Hub price relative to reference case. Reference scenario, shaded in gray, lists Henry Hub prices in 2006 dollars per MMBtu.

5.2. Delivered natural gas prices, including the cost of carbon

Delivered natural gas prices, including the cost of carbon, are largely dependent on electricity sector technology development. High electricity-sector development reduces delivered natural gas prices to electricity generators slightly (< 10%), whereas low electricity-sector development increases delivered prices up to 25% relative to the reference case. Restricting CCS retrofits of existing power plants further increases delivered natural gas prices due to higher GHG emissions allowance prices. Natural gas extraction technology development does not significantly impact delivered natural gas prices. Electricity sector development likely has greater impact on delivered price than natural gas extraction development because electricity sector development determines alternatives to natural gas generation and affects electricity sector GHG emissions, impacting allowance prices.

Figure 4. Average annual delivered natural gas price for electricity generators. Prices include the cost of carbon.

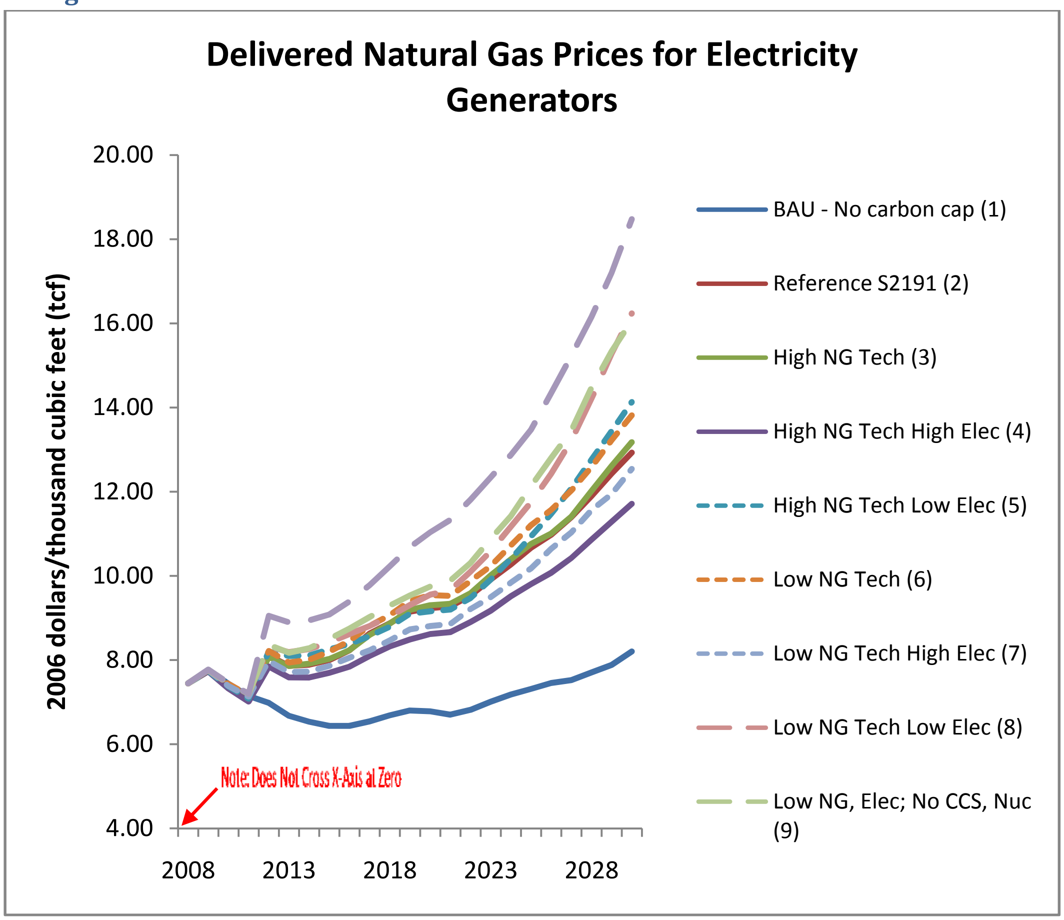


Table 2. Percent change delivered natural gas price for electricity generators from reference scenario.

	2008	2010	2015	2020	2025	2030
Business-as-usual - No carbon cap (1)	0%	1%	-20%	-27%	-31%	-37%
Reference S. 2191 (2)	7.45	7.37	8.00	9.23	10.67	12.93
High NG Tech (3)	0%	0%	0%	1%	1%	2%
High NG Tech High Elec (4)	0%	-1%	-4%	-7%	-8%	-9%
High NG Tech Low Elec (5)	0%	0%	3%	-1%	3%	9%
Low NG Tech (6)	0%	1%	3%	3%	5%	7%
Low NG Tech High Elec (7)	0%	0%	-2%	-5%	-5%	-3%
Low NG Tech Low Elec (8)	0%	1%	5%	4%	10%	26%
Low NG, Elec; No CCS, Nuc (9)	0%	1%	6%	6%	14%	24%
Low NG, Elec; No CCS, Nuc, Retrofit(9b)	0%	1%	14%	20%	26%	43%

Percent change in delivered natural gas price for electricity generators relative to reference case. Prices include the cost of carbon. Reference scenario, shaded in gray, lists delivered natural gas prices for electricity generators in 2006 dollars per thousand cubic feet.

Figure 5. Average annual delivered natural gas price for industrial customers. Prices include the cost of carbon.

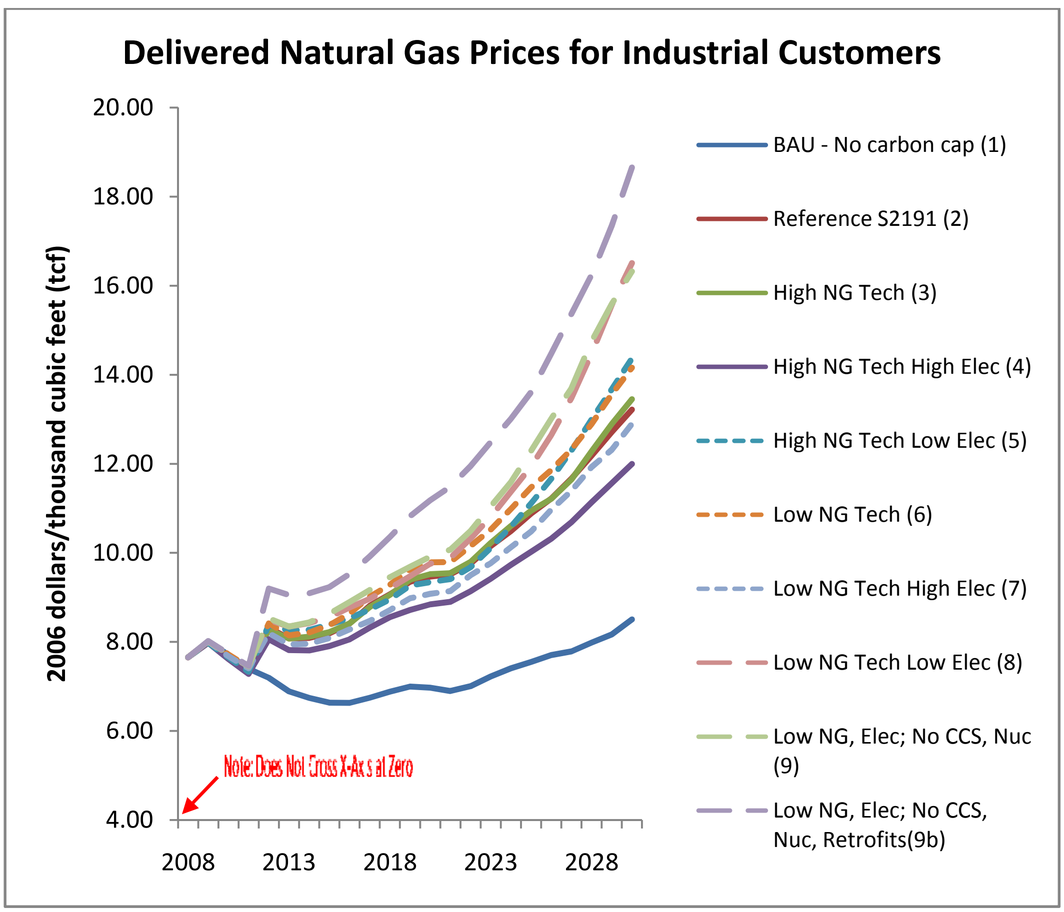


Table 3. Percent change delivered industrial natural gas price from reference scenario.

	2008	2010	2015	2020	2025	2030
Business-as-usual - No carbon cap (1)	0%	1%	-19%	-26%	-31%	-36%
Reference S. 2191 (2)	7.65	7.66	8.19	9.46	10.88	13.22
High NG Tech (3)	0%	0%	0%	1%	1%	2%
High NG Tech High Elec (4)	0%	-1%	-3%	-7%	-8%	-9%
High NG Tech Low Elec (5)	0%	0%	2%	-1%	2%	9%
Low NG Tech (6)	0%	1%	2%	3%	5%	7%
Low NG Tech High Elec (7)	0%	0%	-1%	-4%	-4%	-2%
Low NG Tech Low Elec (8)	0%	1%	5%	3%	10%	25%
Low NG, Elec; No CCS, Nuc (9)	0%	1%	5%	5%	13%	23%
Low NG, Elec; No CCS, Nuc, Retrofit(9b)	0%	1%	13%	18%	25%	41%

Percent change in delivered industrial natural gas price relative to reference case. Prices include the cost of carbon. Reference scenario, shaded in gray, lists delivered natural gas prices for electricity generators in 2006 dollars per thousand cubic feet.

5.3. Industrial natural gas expenditures

U.S. industry is potentially vulnerable to future increases in natural gas prices. Relative to the electricity sector, it is difficult for industry to pass fuel costs on to customers. Cumulative industrial natural gas expenditures, calculated as total industrial consumption multiplied by delivered natural gas price,* are largely dependent on electricity sector technology development (see Figures 6 and 7). The inability to retrofit existing power plants with CCS increases cumulative industrial natural gas expenditures 17%, likely because of higher GHG allowance prices that increase the cost of delivered natural gas.

* Delivered natural gas prices are expressed in 2006 dollars.

Figure 6. Cumulative industrial natural gas expenditures, 2008–2030 (in billions of 2006 dollars).

	High NG Tech	Ref NG Tech	Low NG Tech
High Elec Tech	1,407		1,437
Ref Elec Tech	1,476	1,474	1,504
Low Elec Tech	1,515		1,560
Low Elec Tech, No IGCC CCS or Nuc 2020			1,570
Low Elec Tech, No Retro CCS ever, No CCS or Nuc 2020			1,720

Cumulative expenditures calculated as industrial consumption multiplied by delivered industrial natural gas prices.

Figure 7. 2008-2030 Cumulative industrial natural gas expenditures – percentage change from reference.

	High NG Tech	Ref NG Tech	Low NG Tech
High Elec Tech	-5%		-3%
Ref Elec Tech	0%	0%	2%
Low Elec Tech	3%		6%
Low Elec Tech, No IGCC CCS or Nuc 2020			7%
Low Elec Tech, No Retro CCS ever, No CCS or Nuc 2020			17%

5.4. U.S. natural gas demand

With the exception of scenario 5[*] after 2026, consumers respond to higher delivered natural gas prices, and U.S. demand decreases relative to the business-as-usual scenario without a carbon cap (Figure 8).[†] Total U.S. demand does not increase or decrease by more than 10% across the scenarios, with the

[*] Scenario 5 assumptions: High natural gas extraction technology development, low electricity-sector technology development with Lieberman-Warner (S. 2191)

[†] NI-NEMS has different demand elasticities for each demand source included in the model. See the EIA's NEMS documentation http://tonto.eia.doe.gov/reports/reports_kindD.asp?type=model%20documentation for more information.

exception of scenario 7 (low NG extraction technology and high electricity technology development), which has a 14% decrease in natural gas consumption relative to the reference scenario past 2025 because of more expensive natural gas and better alternative generation technologies such as renewables.

Figure 8. U.S. annual natural gas demand (in trillion cubic feet per year).

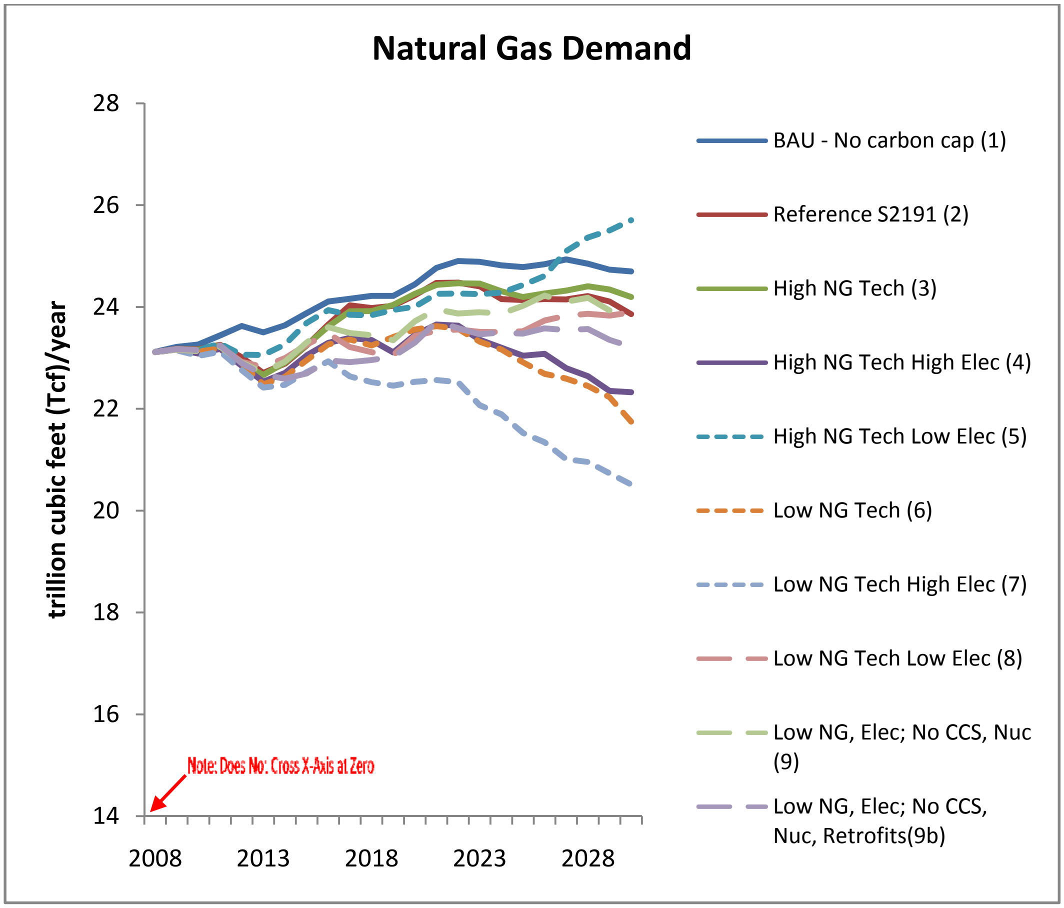


Table 4. Percent change in U.S. natural gas demand from reference scenario.

	2000	2005	2010	2020	2030
Business-as-usual - No carbon cap (1)			0%	1%	4%
Reference S. 2191 (2)	23.3	22	23.2	24.2	23.9
High NG Tech (3)			0%	0%	1%
High NG Tech High Elec (4)			0%	-3%	-6%
High NG Tech Low Elec (5)			0%	-1%	8%
Low NG Tech (6)			0%	-3%	-9%
Low NG Tech High Elec (7)			-1%	-7%	-14%
Low NG Tech Low Elec (8)			0%	-3%	0%
Low NG, Elec; No CCS, Nuc (9)			0%	-2%	0%
Low NG, Elec; No CCS, Nuc, Retrofits(9b)			0%	-4%	-3%

Percent change in U.S. natural gas demand relative to reference case. Reference scenario, shaded in gray, lists U.S. natural gas demand in trillion cubic feet per year.

Electricity sector natural gas demand varies significantly among scenarios (Figure 9). Low natural gas extraction technology development and high electricity-sector technology development (scenarios 4, 6, and 7) decrease natural gas demand relative to the reference scenario because of lower supply and electricity generation alternatives. High natural gas extraction development and low electricity-sector development (scenario 5) increase natural gas demand more than 10% relative to the reference scenario after 2027 due to greater supply and fewer generation alternatives. For all other scenarios (1, 3, 8, and 9), electricity sector natural gas demand is similar to the reference case. High variability in electricity sector natural gas demand does not create the same level of variability in total natural gas demand because the electricity sector only represents around 30% of total natural gas demand (see Figure 9a, in the Appendix A). Relative to the business-as-usual scenario without a cap, a carbon cap decreases U.S. natural gas consumption in all sectors except electricity with little variation (Figure 10). This large difference in variability between the electricity sector and other sectors, mainly residential, commercial and industrial, is likely due to two main factors. First, the CCPP did not adjust inputs for the residential, commercial, and industrial sectors. Second, consumers in the residential, commercial, and industrial sectors cannot easily switch to alternative fuels and thus will likely respond to higher prices with conservation and increased efficiency, whereas electricity generators can choose from a variety of generation sources to lower fuel costs and comply with a carbon cap.

Figure 9. Annual electricity sector natural gas demand in trillion cubic feet per year.

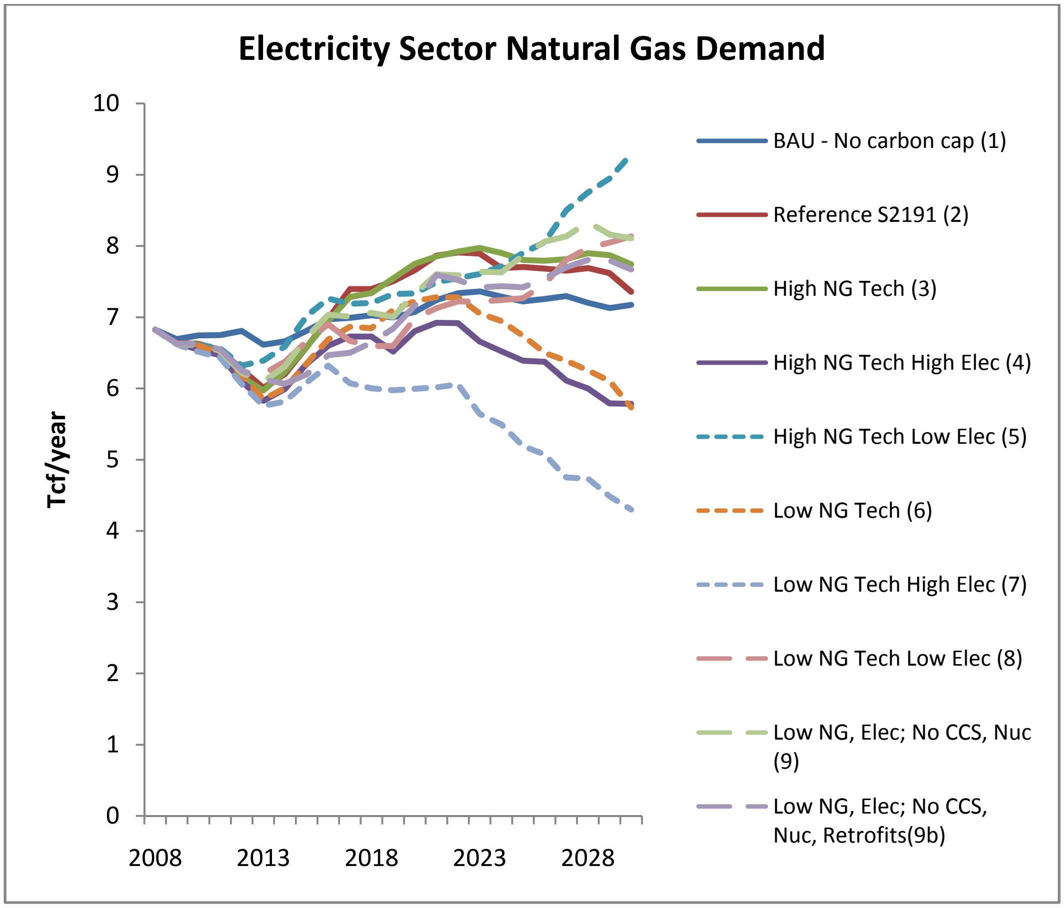
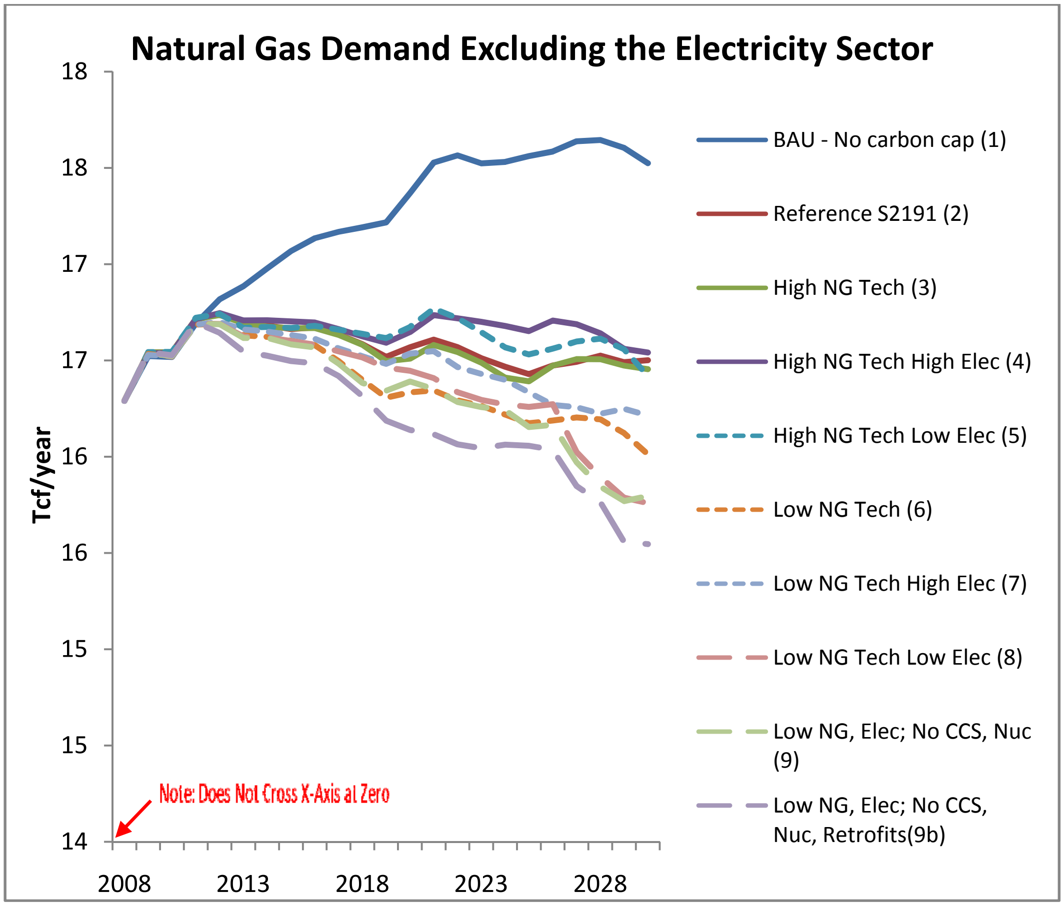


Table 5. Percent change Electricity Sector Natural Gas Demand from Reference Scenario.

	2008	2010	2015	2020	2025	2030
Business-as-usual - No carbon cap (1)	0%	2%	3%	-8%	-6%	-2%
Reference S. 2191 (2)	6.8	6.6	6.6	7.7	7.7	7.4
High NG Tech (3)	0%	0%	0%	1%	1%	5%
High NG Tech High Elec (4)	0%	-1%	-4%	-11%	-17%	-21%
High NG Tech Low Elec (5)	0%	0%	7%	-4%	3%	26%
Low NG Tech (6)	0%	0%	-3%	-6%	-13%	-22%
Low NG Tech High Elec (7)	0%	-2%	-8%	-22%	-33%	-42%
Low NG Tech Low Elec (8)	0%	0%	1%	-9%	-6%	11%
Low NG, Elec; No CCS, Nuc (9)	0%	0%	2%	-4%	2%	10%
Low NG, Elec; No CCS, Nuc, Retrofit(9b)	0%	0%	-6%	-6%	-4%	4%

Percent change in electricity sector natural gas demand relative to reference case. Reference scenario, shaded in gray, lists electricity sector natural gas demand in trillion cubic feet per year.

Figure 10. Annual natural gas demand excluding the electricity sector in trillion cubic feet per year.

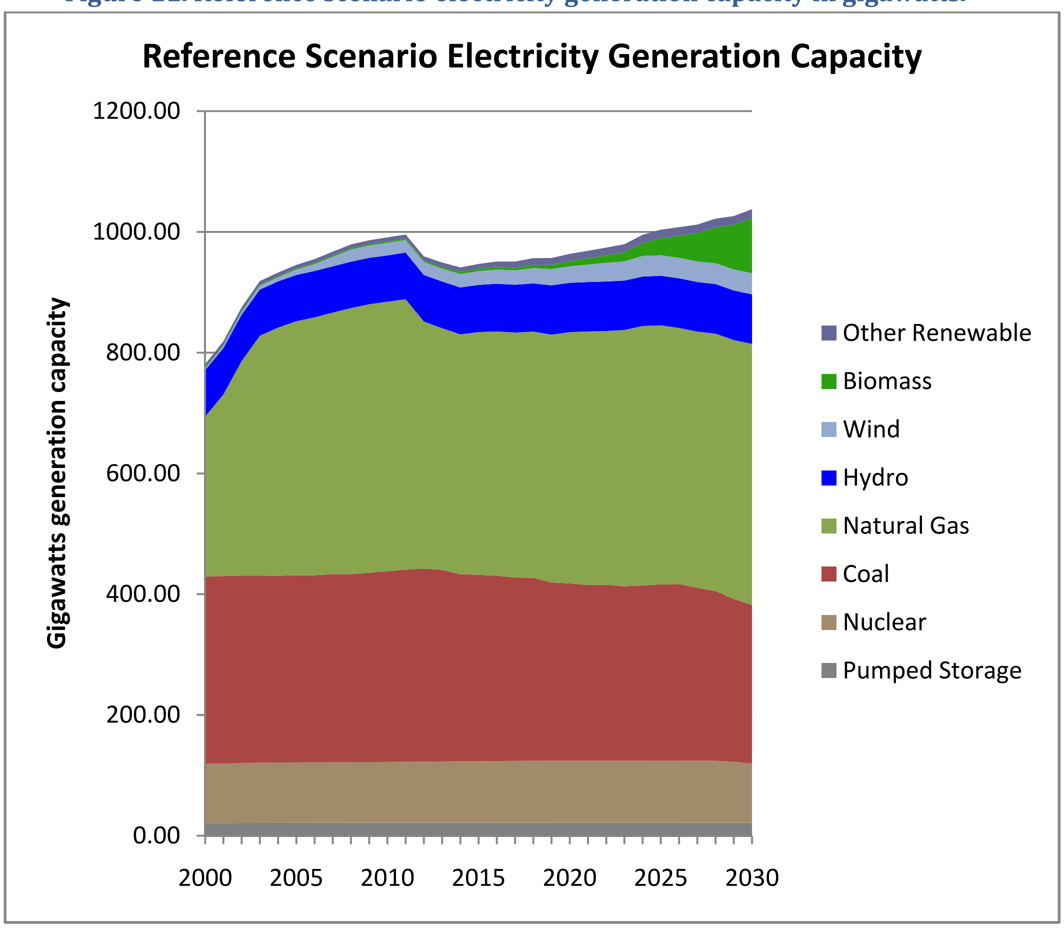


6. Electricity Sector Results

6.1. Electricity generation capacity

For all scenarios, total electricity generation capacity decreases in 2012 and then, with the exception of the most restrictive scenario (9b), gradually increase after 2015. High electricity-sector technology development decreases the costs of building low-carbon emissions generation capacity, increasing total generation capacity. Low electricity-sector technology development has the opposite effect, decreasing total generation capacity relative to the reference scenario. The share of generation technology for the reference scenario changes over time in response to the carbon cap (Figure 11). Coal capacity decreases while renewable capacity increases and nuclear and natural gas generation remain stable. All other scenarios, besides the business-as-usual scenario without a carbon cap, have similar trends with natural gas increasing and renewables increasing at a slower rate under low electricity-sector technology development and lower decreases in coal capacity under high electricity-sector development relative to the reference scenario.

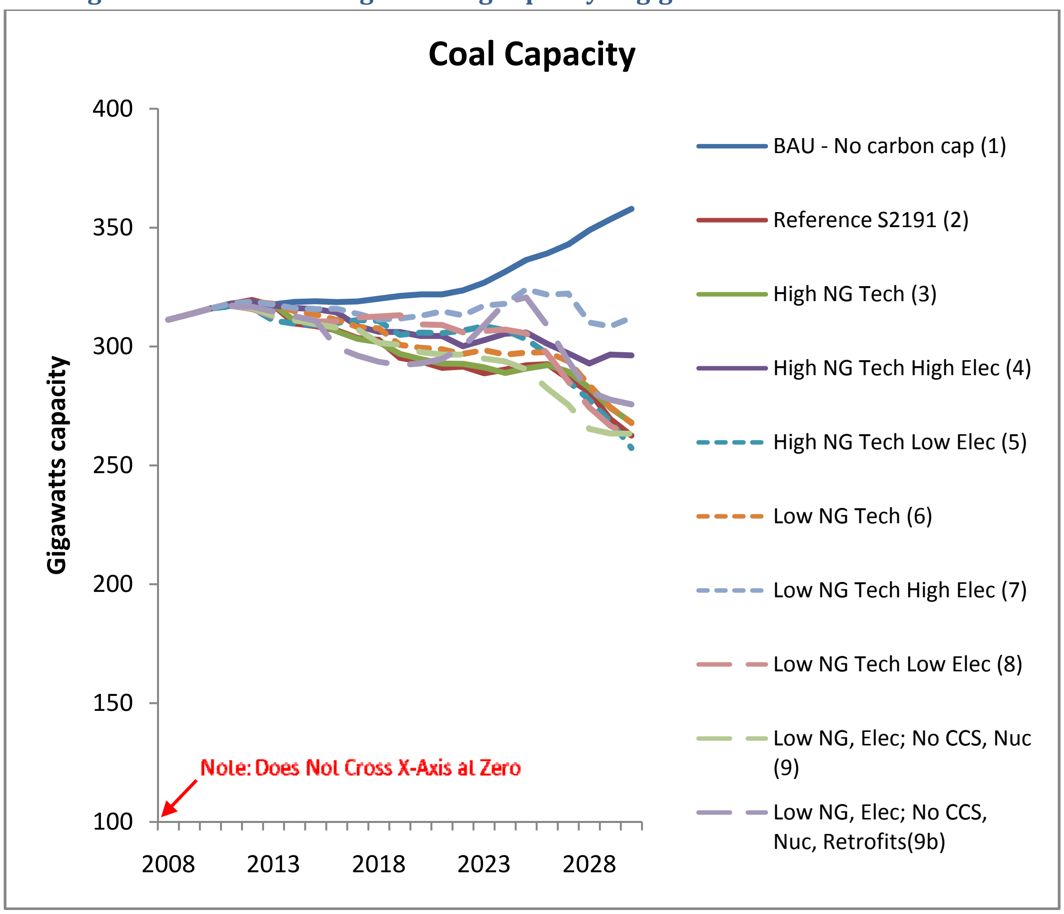
Figure 11. Reference scenario electricity generation capacity in gigawatts.



6.2. Coal generation capacity

Future coal capacities are lower in 2030 than in 2010 for all scenarios with a carbon cap (Figure 12). High electricity-sector technology development has the greatest impact on coal capacity, relative to the reference case, increasing capacity by 13% in 2030. High electricity-sector development lowers costs for CCS and renewable generation, increasing CCS and renewable capacity (Figures 13 and 17, respectively), creating more room under a cap for coal generation. See Appendix A for total capacity with CCS retrofits (Figure 13a). Under no scenario does coal capacity decrease by more than 6% relative to the reference case for any year in the model as coal continues to be a critical generation resource regardless of technology constraints. For all scenarios, at least 74% of the 2030 coal capacity was operating in 2008.*

Figure 12. National coal generating capacity in gigawatts.



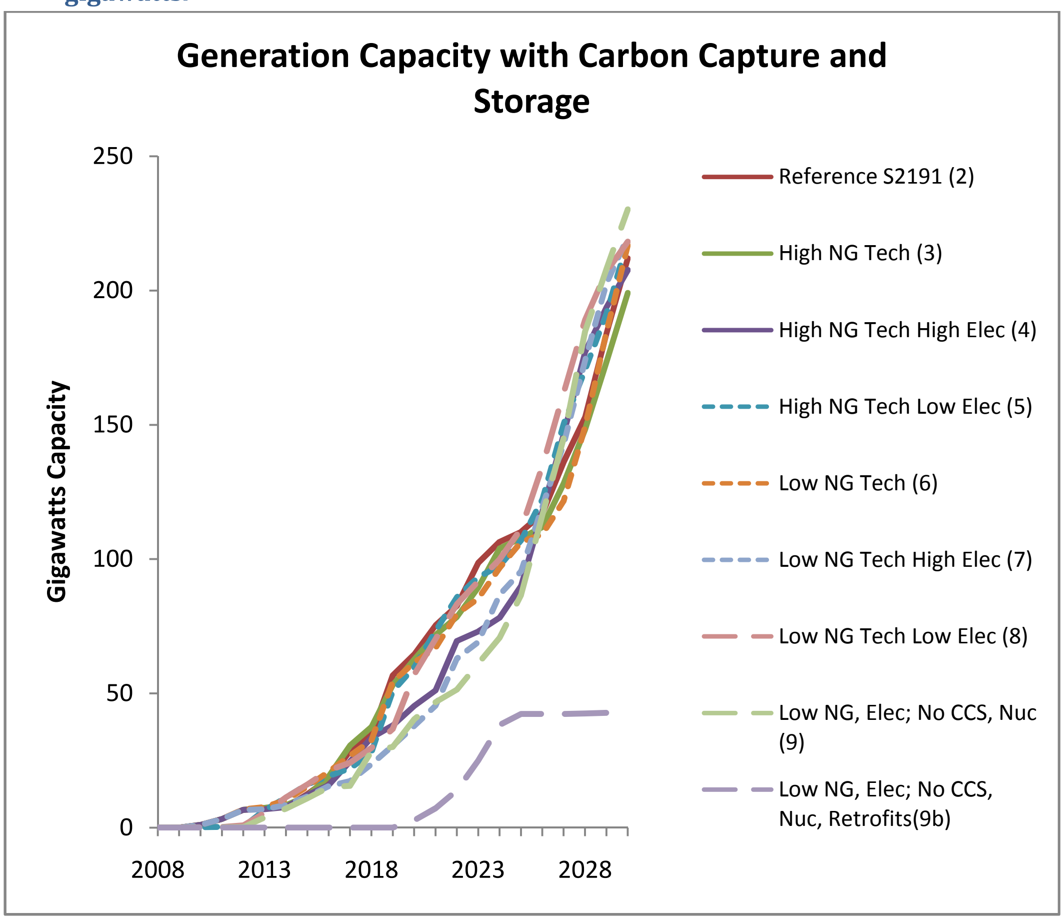
* Please note that capacity operating in 2008 may have undergone upgrades including CCS retrofits after 2008.

Table 6. Percent change in coal capacity from reference scenario.

	2008	2010	2015	2020	2025	2030
Business-as-usual - No carbon cap (1)	0%	0%	3%	10%	15%	36%
Reference S. 2191 (2)	311	316	309	294	292	262
High NG Tech (3)	0%	0%	1%	0%	0%	2%
High NG Tech High Elec (4)	0%	0%	2%	4%	5%	13%
High NG Tech Low Elec (5)	0%	0%	0%	4%	4%	-2%
Low NG Tech (6)	0%	0%	2%	2%	2%	2%
Low NG Tech High Elec (7)	0%	0%	2%	7%	11%	19%
Low NG Tech Low Elec (8)	0%	0%	1%	5%	5%	0%
Low NG, Elec; No CCS, Nuc (9)	0%	0%	0%	1%	-1%	0%
Low NG, Elec; No CCS, Nuc, Retrofit(9b)	0%	0%	1%	0%	10%	5%

Percent change in coal capacity relative to reference case. Reference scenario, shaded in gray, lists coal capacity in gigawatts.

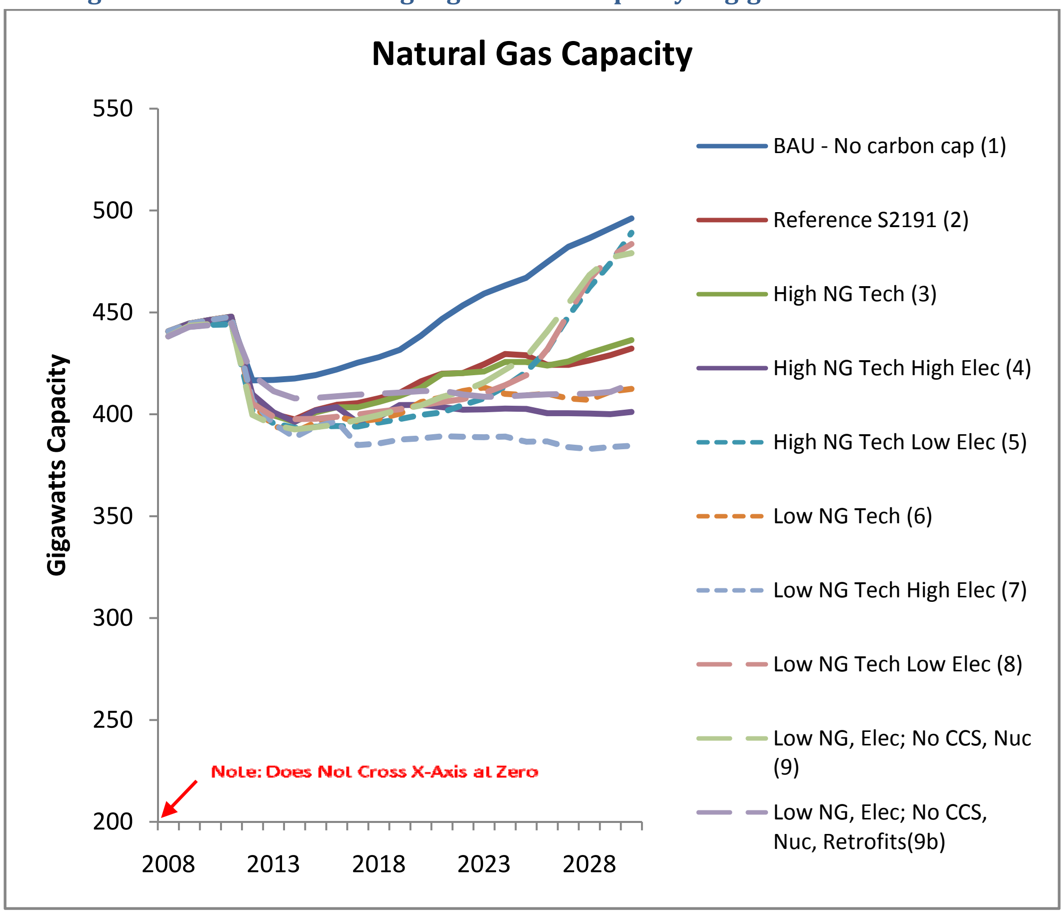
Figure 13. National generation capacity with carbon capture and storage in gigawatts.



6.3. Natural gas generation capacity

Natural gas capacity decreases sharply in 2012 for all scenarios as older, less efficient natural gas steam generation plants and conventional natural gas turbines are retired to remove the excess generation capacity[34] found in most areas of the United States (Figures 14, 15, and 16).[*] Natural gas generation is relatively easy to retire and replace because it has the lowest construction costs (Table 17a) and relatively short construction times. After 2012, natural gas capacity stays relatively constant for all scenarios with a carbon cap until about 2025, when it increases for three low electricity-sector technology development scenarios to compensate for low renewable capacity growth (5, 8, and 9). Low electricity-sector development increases the relative cost of newer technologies like CCS and renewables compared to mature generation technologies like natural gas combined cycle, encouraging natural gas capacity growth. For all scenarios, at least 78% of the 2030 natural gas capacity was operating in 2008.[†]

Figure 14. National natural gas generation capacity in gigawatts.



[*] For all scenarios, there are no combined cycle or advanced natural gas turbine retirements through 2030.
[†] Please note that capacity operating in 2008 may have undergone upgrades including CCS retrofits after 2008.

Figure 16. Reference scenario cumulative natural gas steam generation retirements.

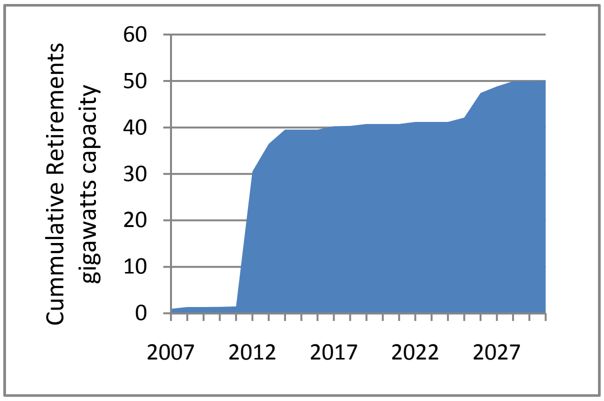
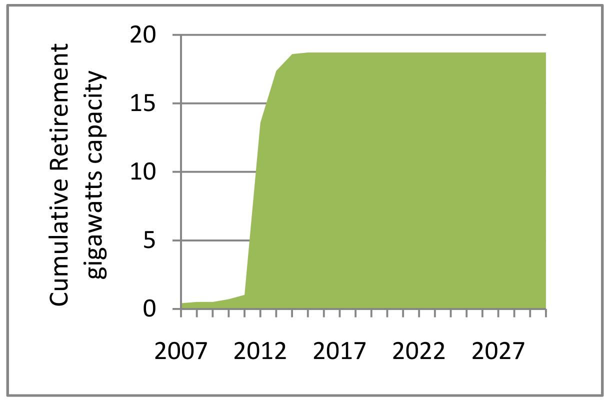


Figure 15. Reference scenario cumulative natural gas conventional turbine retirements.



6.4. Renewable capacity

Total renewable generation capacity increases over 100% from 2008 to 2030 for normal and high electricity-sector technology development scenarios with a carbon cap but only increases approximately 33% from 2008 to 2030 for the low electricity-sector technology development scenarios (Figure 18). For the CCPP's scenarios, the resulting renewable capacity growth is a substitute for additional natural gas capacity. In the normal and high electricity development scenarios with a carbon cap, renewable capacity approximately doubles while natural gas capacity remains relatively constant. In the low electricity development scenarios, natural gas capacity increases to make up for lower renewable capacity growth.

For the reference scenario, the largest increases in renewable capacity are biomass, followed by wind (Figure 11). A carbon cap restricts alternative fossil fuel generation sources, encouraging renewable capacity development for all scenarios relative to the business-as-usual scenario without a cap (Figure 17). Renewable generation capacity has far greater variation between scenarios (by percentage) than natural gas or coal generation capacity (Table 7). NI-NEMS assumes the production tax credit for wind expires December 31, 2008. After the CCPP completed its modeling, Congress extended the production tax credit for wind through December 31, 2012. CCPP wind capacity forecasts would likely be higher with the extended production tax credit.

Figure 17. National renewable generation capacity in gigawatts.

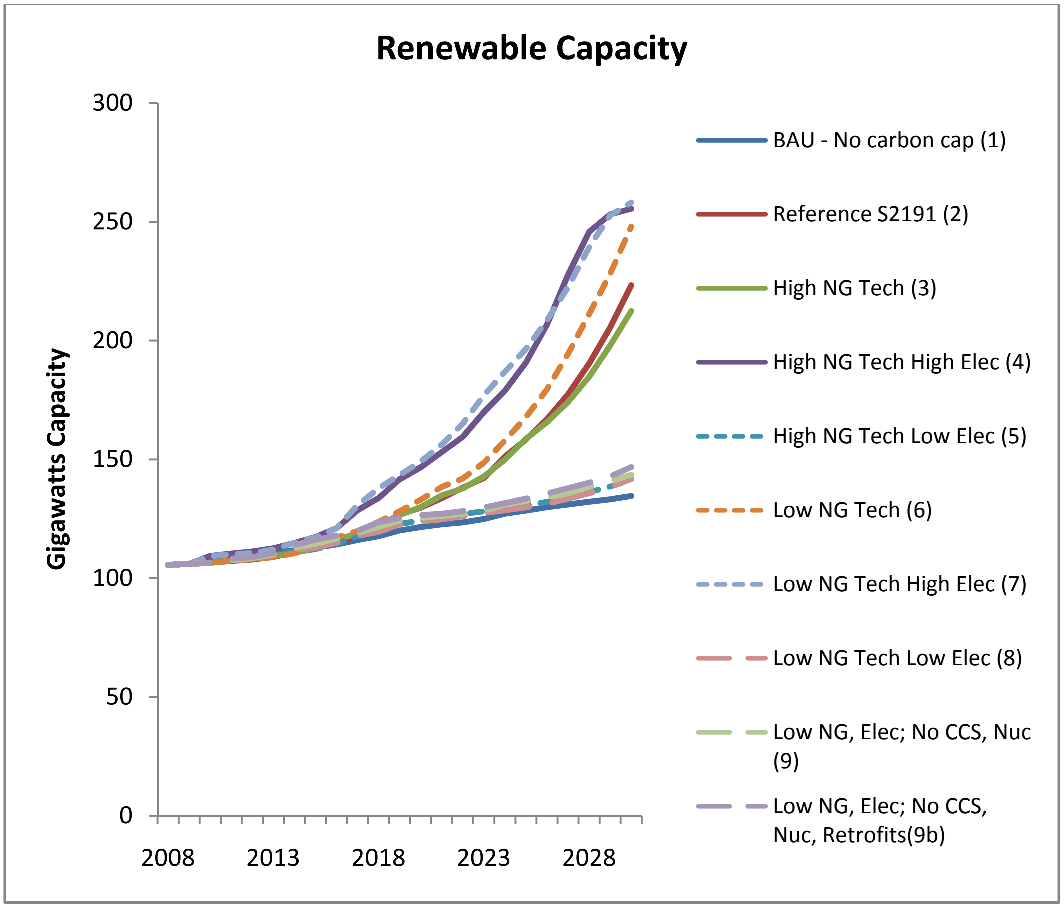


Table 7. Percent change in renewable capacity from reference scenario.

	2008	2010	2015	2020	2025	2030
Business-as-usual - No carbon cap (1)	0%	1%	0%	-6%	-19%	-40%
Reference S. 2191 (2)	106	107	113	130	158	223
High NG Tech (3)	0%	0%	-1%	0%	0%	-5%
High NG Tech High Elec (4)	0%	3%	4%	13%	20%	14%
High NG Tech Low Elec (5)	0%	0%	-1%	-4%	-17%	-37%
Low NG Tech (6)	0%	0%	0%	3%	6%	11%
Low NG Tech High Elec (7)	0%	3%	4%	15%	24%	16%
Low NG Tech Low Elec (8)	0%	0%	0%	-4%	-18%	-37%
Low NG, Elec; No CCS, Nuc (9)	0%	0%	1%	-3%	-16%	-36%
Low NG, Elec; No CCS, Nuc, Retrofit(9b)	0%	0%	3%	-2%	-16%	-34%

Percent change in renewable capacity relative to reference case. Reference scenario, shaded in gray, lists renewable capacity in gigawatts.

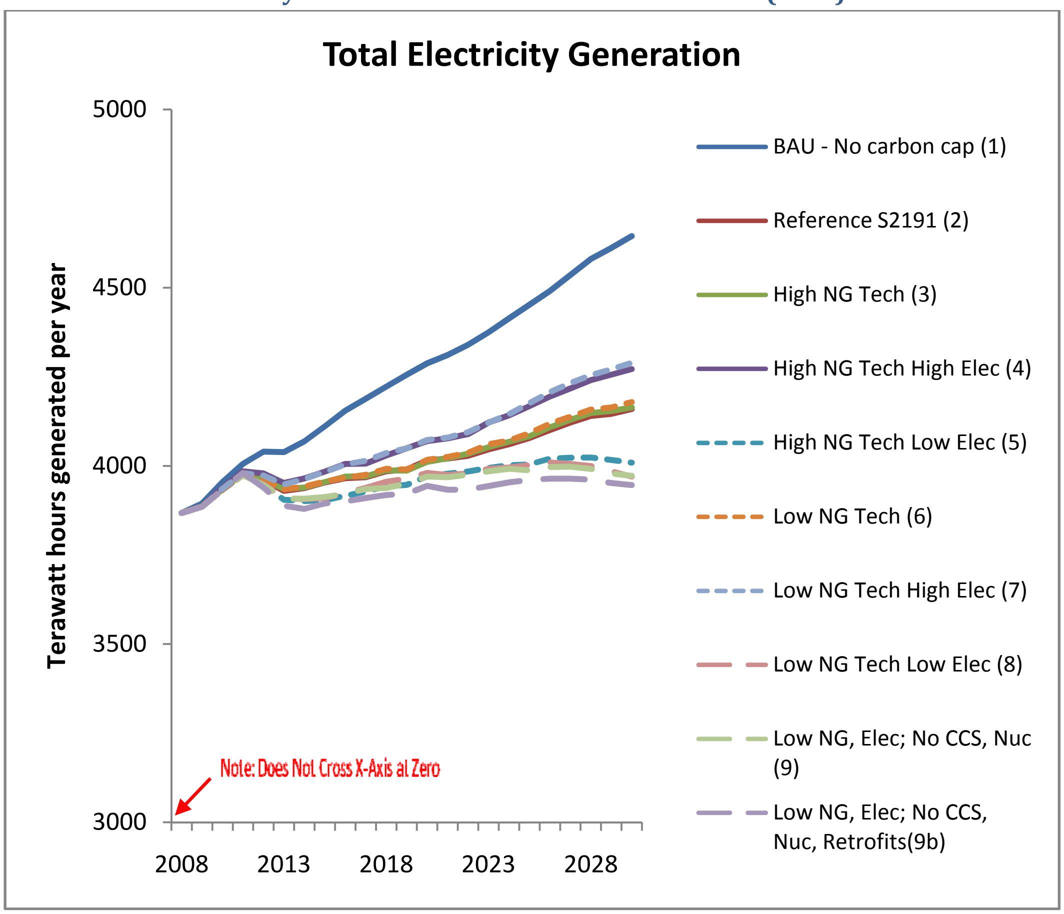
6.5. Nuclear generation capacity

Despite several electric utilities filing for new construction approval from the Nuclear Regulatory Commission, nuclear capacity is unchanged across all scenarios through 2030 as no new nuclear power plants are constructed during the simulations. The omission of new nuclear generating capacity by NI-NEMS is due to the high cost of nuclear making it uncompetitive with other generation sources, and the lack of certainty needed to confidently include a new nuclear plant in the model exogenously. Total nuclear electricity generation and capacity factors remain constant for all scenarios.

6.6. Electricity generation

For all scenarios other than the business-as-usual scenario without a carbon cap, electricity demand remains stagnant or increases by less than 0.5% per year* as consumers respond to increasing electricity prices. For scenarios with restricted electricity-sector technology growth (5, 8, 9a, 9b), total electricity generation is roughly constant at 4,000 terawatt hours per year through 2030 (Figure 18). On a per capita basis, residential electricity demand decreases for all scenarios between 2010 and 2030 (Table 8).

Figure 18. Annual electricity generation by all companies or other entities who sell electricity in the United States in terawatt hours (TWh).



* From 2010–2030

Table 8. Per capita residential electricity demand

	2008	2010	2020	2030	% Change 2010 - 2030
Business-as-usual - No carbon cap (1)	4,600	4,658	4,536	4,642	**−0.3%**
Reference S. 2191 (2)	4.600	4,636	4,233	4,116	**−11%**
High NG Tech (3)	4,600	4,635	4,230	4,115	**−11%**
High NG Tech High Elec (4)	4,600	4,636	4,267	4,180	**−10%**
High NG Tech Low Elec (5)	4,600	4,633	4,214	4,046	**−13%**
Low NG Tech (6)	4,600	4,634	4,226	4,106	**−11%**
Low NG Tech High Elec (7)	4,600	4,633	4,260	4,168	**−10%**
Low NG Tech Low Elec (8)	4,600	4,634	4,214	4,004	**−14%**
Low NG, Elec; No CCS, Nuc (9)	4,600	4,634	4,208	4,000	**−14%**
Low NG, Elec; No CCS, Nuc, Retrofits(9b)	4,600	4,635	4,168	3,965	**−14%**

Per capita residential electricity demand, kWh per year, calculated as total residential electricity sales/population.

6.7. Electricity generation by source

Coal electricity generation decreases under a carbon cap with minimal variability between the scenarios, excluding the business-as-usual scenario without a cap, compared to natural gas and renewable generation, indicating that natural gas is not a substitute for coal generation (Figures 19, 20, and 21 and Tables 9, 10, and 11). Except in the most restricted technology scenario (9b), natural gas and renewable generation are inversely correlated under a carbon cap and vary significantly between scenarios. Scenarios with higher natural gas generation have lower renewable generation and vice versa. See Figures 22, 23, and 24 for electricity generation by source for each scenario in 2010, 2020, and 2030, respectively. As seen in Figure 24, by 2030 renewable generation surpasses natural gas generation for all scenarios (2, 3, 4, 6, and 7) with baseline and high electricity-sector technology development and a carbon cap.

The most significant factor in natural gas and renewable electricity generation appears to be electricity sector technology development, not natural gas extraction technology development. Electricity sector development affects natural gas generation capacity and natural gas sector capacity factors. For scenarios (4 and 7) with high electricity-sector development and the low natural gas technology development scenario (6), natural gas electricity generation is lower than the reference scenario (2) after 2010. High electricity-sector development also decreases natural gas capacity factors by more than one third in 2030 compared to low electricity-sector technology development scenarios.

A carbon cap increases renewable electricity generation for all scenarios. For scenarios (5, 8, 9a, and 9b) with low electricity-sector technology development, renewable generation is at least 43% less than reference scenario renewable generation in 2030, whereas in the high electricity-sector technology development scenarios (4 and 7), renewable generation increases over 16% compared to the reference scenario beyond 2020.

Figure 19. Coal electricity generation terawatt hours (TWh).

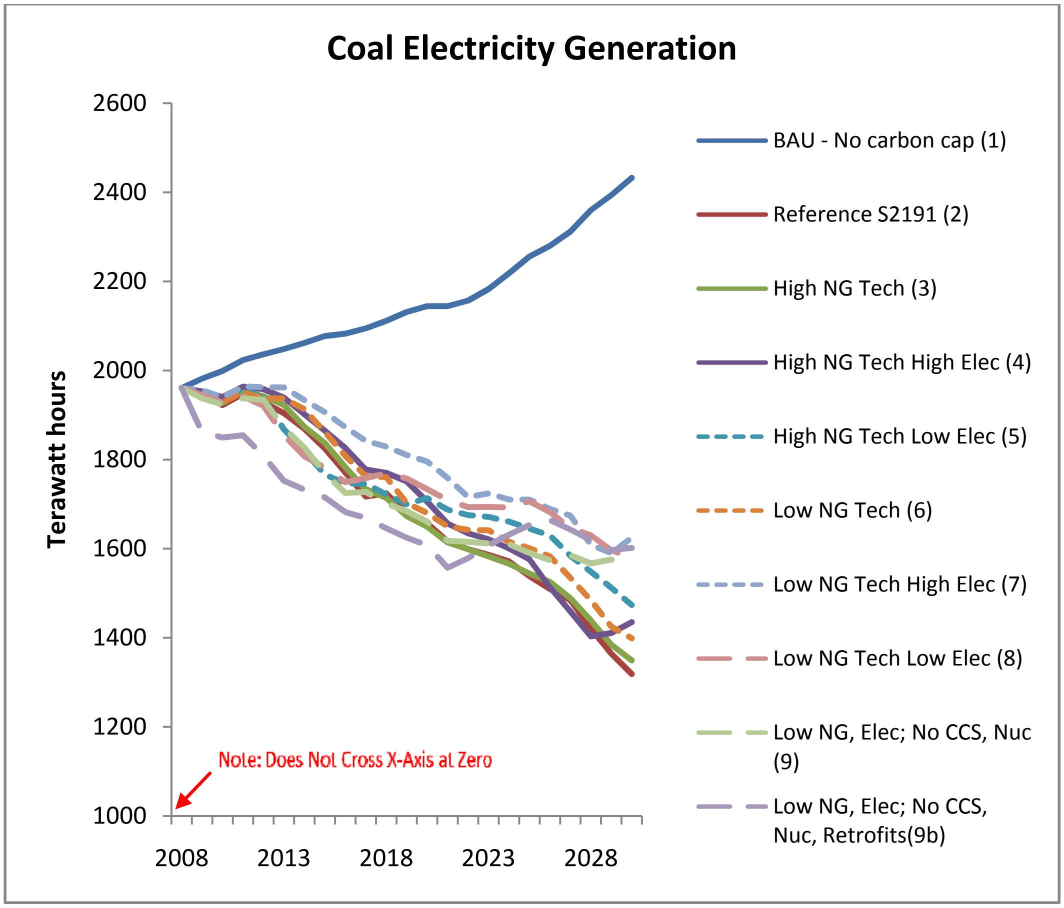


Table 9. Percent change in Coal Electricity Generation from Reference Scenario.

	2008	2010	2015	2020	2025	2030
Business-as-usual - No carbon cap (1)	0%	4%	14%	29%	47%	84%
Reference S. 2191 (2)	1961	1922	1825	1657	1538	1319
High NG Tech (3)	0%	0%	1%	0%	0%	2%
High NG Tech High Elec (4)	0%	1%	2%	3%	2%	9%
High NG Tech Low Elec (5)	0%	1%	-3%	3%	7%	12%
Low NG Tech (6)	0%	0%	2%	1%	4%	6%
Low NG Tech High Elec (7)	0%	1%	4%	8%	11%	23%
Low NG Tech Low Elec (8)	0%	0%	-2%	5%	11%	20%
Low NG, Elec; No CCS, Nuc (9)	0%	0%	-3%	0%	3%	19%
Low NG, Elec; No CCS, Nuc, Retrofit(9b)	0%	-4%	-6%	-3%	7%	21%

Percent change in coal generation relative to reference case. Reference scenario, shaded in gray, lists coal generation in terawatt hours per year.

Figure 20. Natural gas electricity generation in terawatt hours.

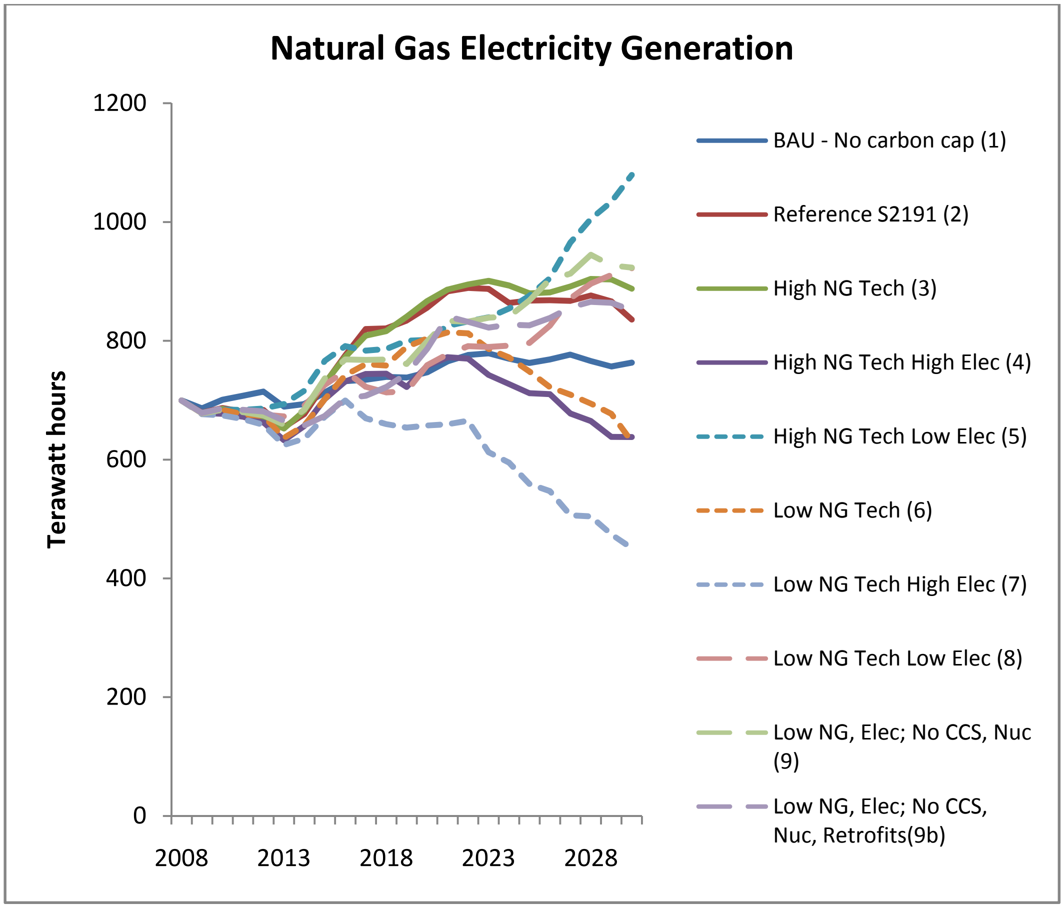


Table 10. Percent change in natural gas electricity generation from reference scenario.

	2008	2010	2015	2020	2025	2030
Business-as-usual - No carbon cap (1)	0%	2%	-2%	-13%	-12%	-9%
Reference S. 2191 (2)	699	687	728	855	868	836
High NG Tech (3)	0%	0%	0%	1%	1%	6%
High NG Tech High Elec (4)	0%	-1%	-4%	-11%	-18%	-24%
High NG Tech Low Elec (5)	0%	0%	5%	-6%	1%	29%
Low NG Tech (6)	0%	0%	-4%	-6%	-14%	-25%
Low NG Tech High Elec (7)	0%	-2%	-8%	-23%	-36%	-46%
Low NG Tech Low Elec (8)	0%	0%	0%	-11%	-8%	10%
Low NG, Elec; No CCS, Nuc (9)	0%	0%	1%	-7%	0%	10%
Low NG, Elec; No CCS, Nuc, Retrofit(9b)	0%	0%	-7%	-8%	-5%	2%

Percent change in natural gas generation relative to reference case. Reference scenario, shaded in gray, lists natural gas generation in terawatt hours per year.

Figure 21. Renewable electricity generation in terawatt hours.

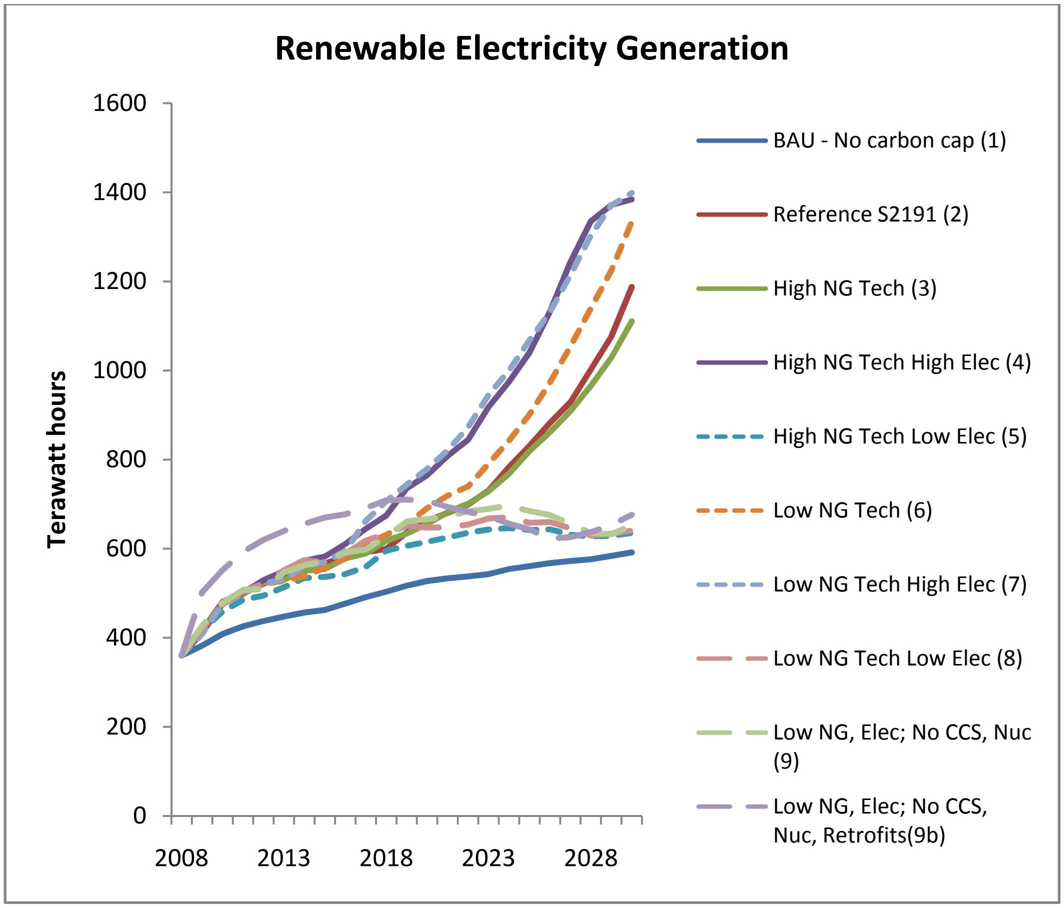


Table 11. Percent change in renewable electricity generation from reference scenario.

	2008	2010	2015	2020	2025	2030
Business-as-usual - No carbon cap (1)	0%	-15%	-18%	-20%	-32%	-50%
Reference S. 2191 (2)	360	480	566	655	830	1188
High NG Tech (3)	0%	-1%	-2%	-1%	-1%	-7%
High NG Tech High Elec (4)	0%	-1%	3%	16%	25%	17%
High NG Tech Low Elec (5)	0%	-4%	-5%	-7%	-23%	-47%
Low NG Tech (6)	0%	-1%	-2%	4%	8%	12%
Low NG Tech High Elec (7)	0%	-1%	1%	18%	29%	18%
Low NG Tech Low Elec (8)	0%	-1%	0%	-2%	-21%	-46%
Low NG, Elec; No CCS, Nuc (9)	0%	0%	1%	1%	-18%	-45%
Low NG, Elec; No CCS, Nuc, Retrofit(9b)	0%	15%	18%	7%	-23%	-43%

Percent change in renewable generation relative to reference case. Reference scenario, shaded in gray, lists renewable generation in terawatt hours per year.

Figure 22. 2010 electricity generation by fuel source in terawatt hours.

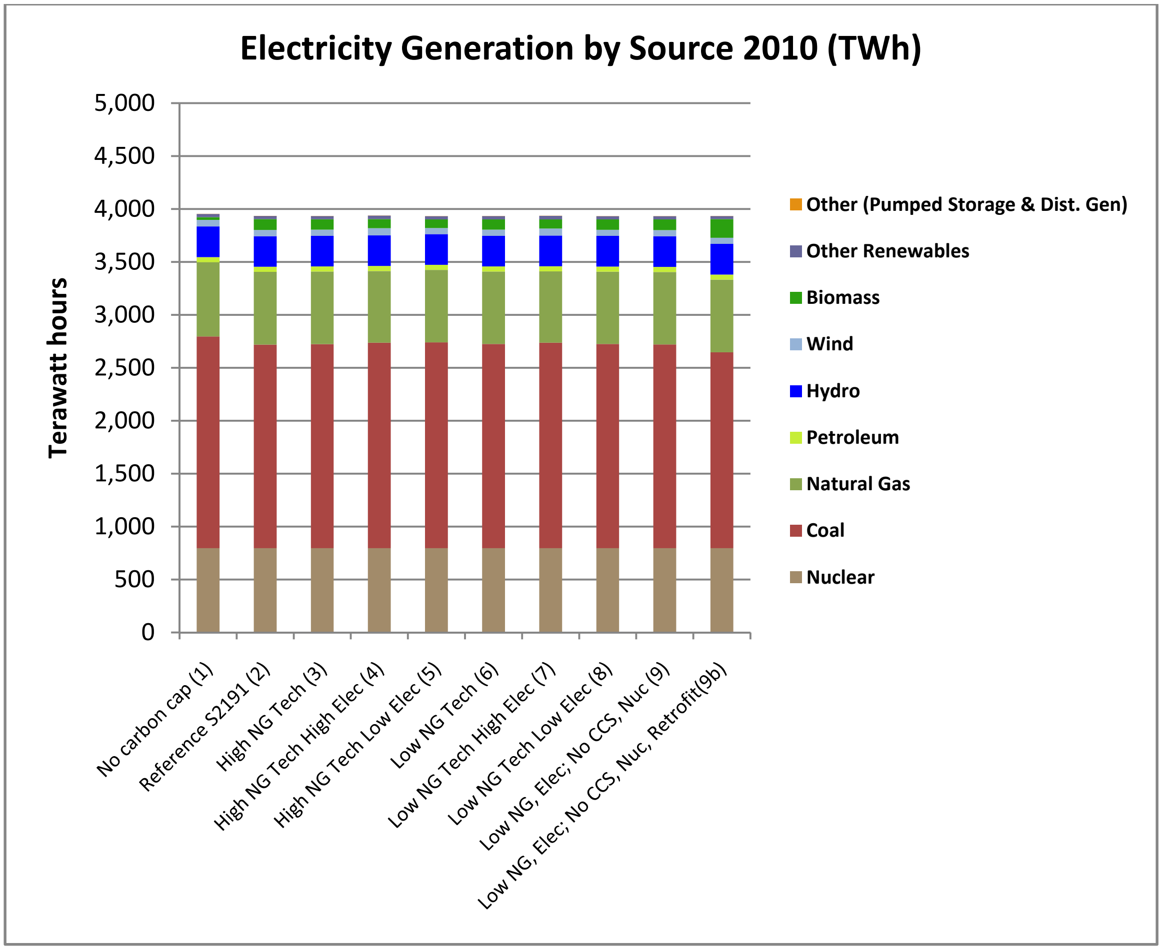


Figure 23. 2020 electricity generation by fuel source in terawatt hours.

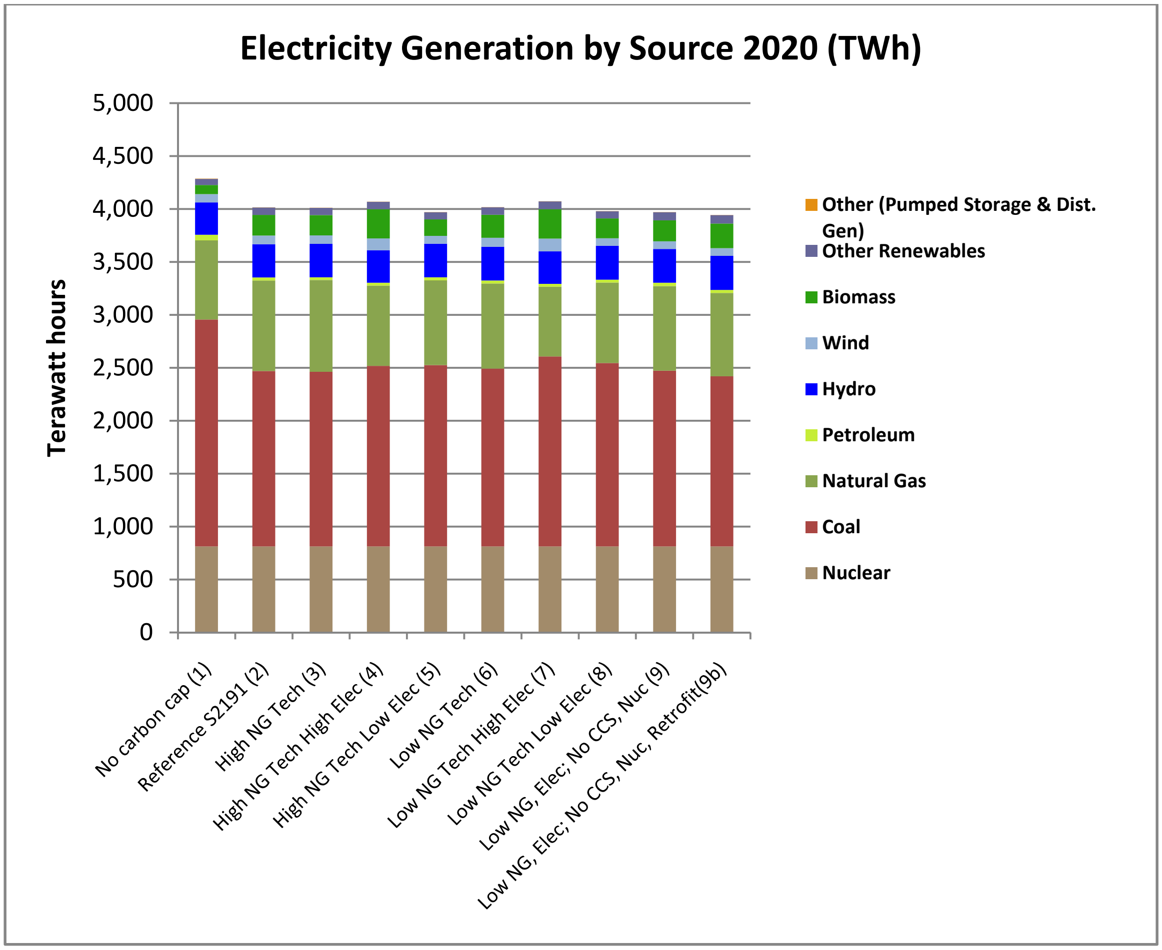
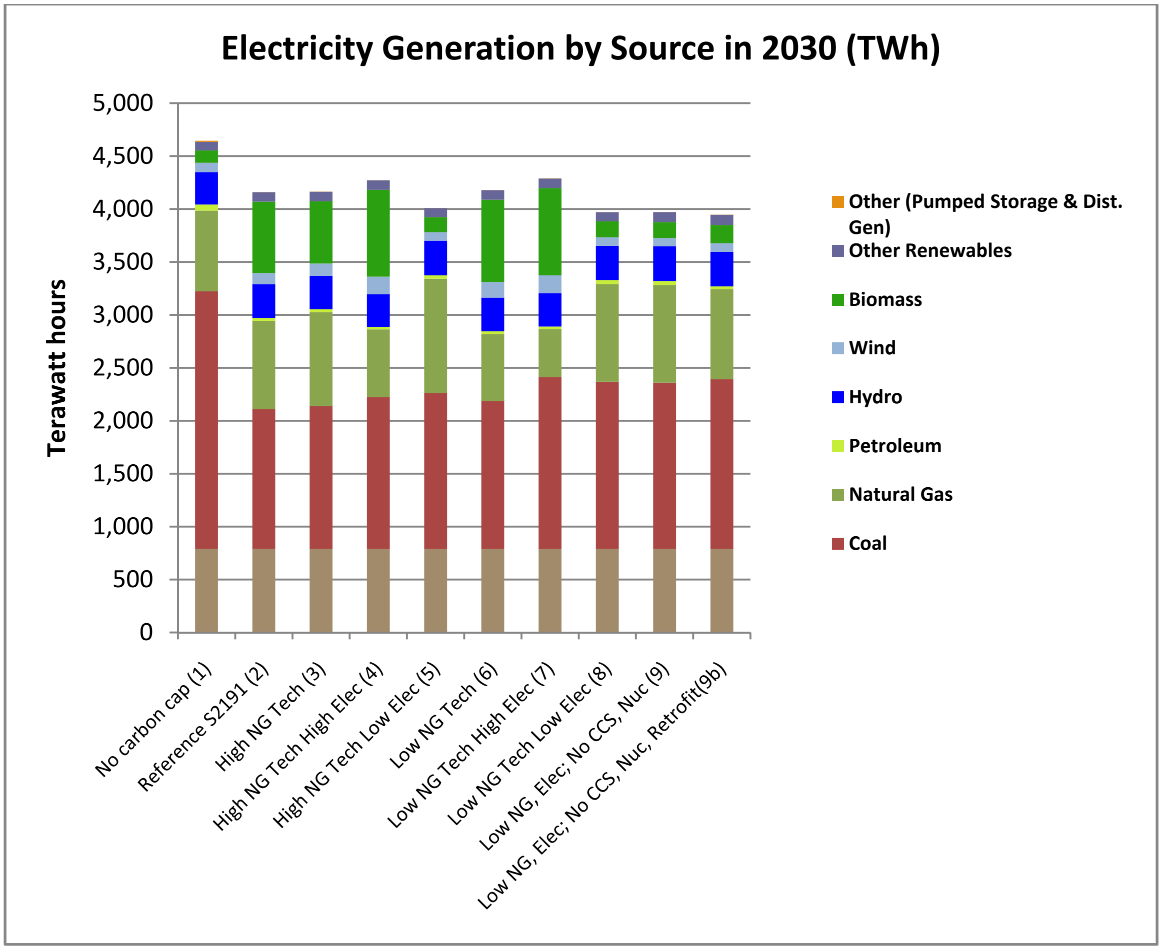


Figure 24. 2030 electricity generation by fuel source in terawatt hours.



6.8. Average electricity prices

Electricity prices are highly dependent upon electricity sector development and restrictions on CCS and CCS retrofits. Changes in natural gas technology development have minimal impact on future electricity prices. Restricted electricity-sector technology development raises average electricity prices at least 12% by 2030 relative to the reference case, and the inability to retrofit existing power plants with CCS further raises prices. Please note that customers' electricity bills will not increase proportionally to the per unit price increase because consumers react to higher prices with conservation and more efficient consumption.

Figure 25. Average annual electricity price in 2006 cents per kilowatt-hour (kWh).

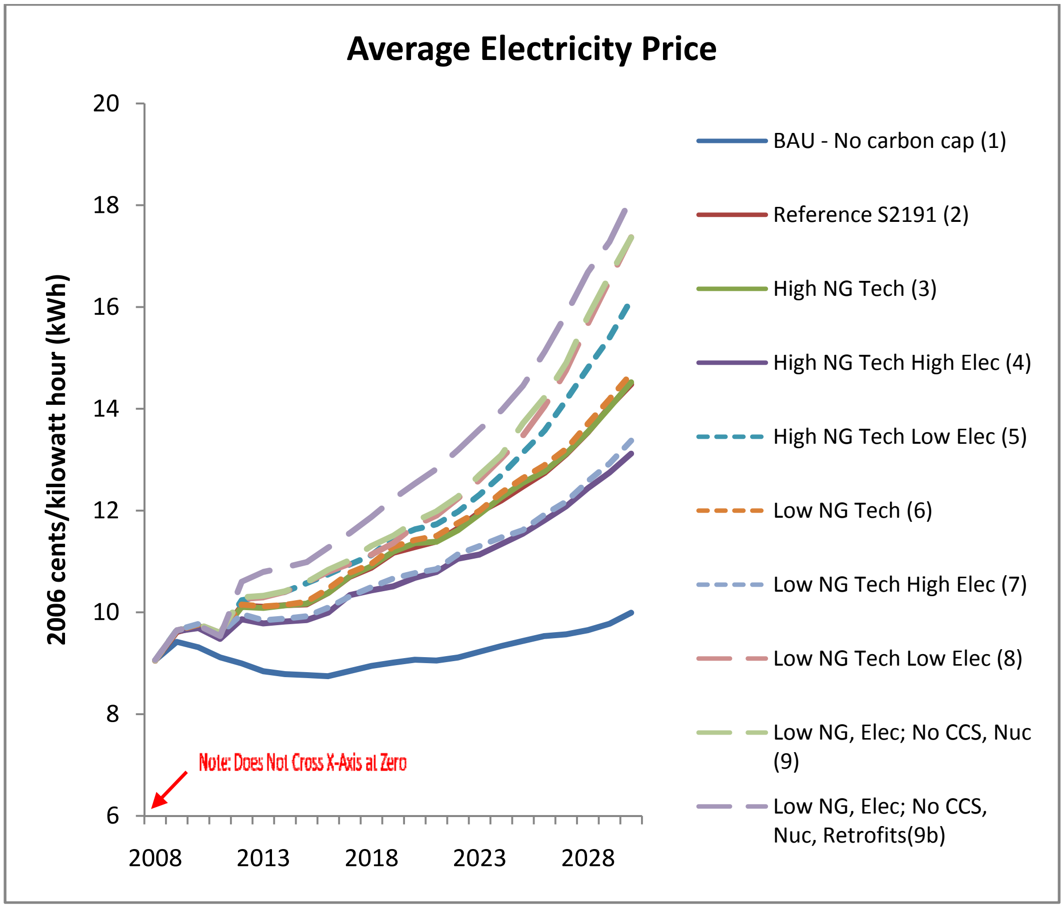


Table 12: Percent change in average electricity price from reference scenario.

	2008	2010	2015	2020	2025	2030
Business-as-usual - No carbon cap (1)	0%	-4%	-14%	-20%	-24%	-31%
Reference S. 2191 (2)	9.05	9.72	10.16	11.28	12.47	14.48
High NG Tech (3)	0%	0%	0%	1%	1%	0%
High NG Tech High Elec (4)	0%	0%	-3%	-5%	-7%	-9%
High NG Tech Low Elec (5)	0%	0%	4%	3%	5%	12%
Low NG Tech (6)	0%	0%	1%	1%	1%	1%
Low NG Tech High Elec (7)	0%	0%	-2%	-5%	-7%	-8%
Low NG Tech Low Elec (8)	0%	0%	4%	4%	8%	20%
Low NG, Elec; No CCS, Nuc (9)	0%	0%	4%	4%	10%	20%
Low NG, Elec; No CCS, Nuc, Retrofit(9b)	0%	0%	8%	11%	16%	25%

Percent change in average electricity price relative to reference case. Reference scenario, shaded in gray, lists average electricity prices in 2006 cents per kWh.

6.9. Residential electricity costs

Per capita residential electricity expenditures increase for all scenarios but less on a percentage basis than electricity prices. Per capita residential electricity expenditures increase 15% from 2008 to 2020 in the reference case (Table 13), whereas average electricity prices increase 25% from 2008 to 2020 in the reference case (Table 12). Per capita residential electricity expenditures vary less between scenarios than average electricity prices, again reflecting consumers' demand response to higher prices.

Table 13: Percent change in per capita annual residential electricity costs from reference scenario.

	2008	2010	2015	2020	2025	2030
Business-as-usual - No carbon cap (1)	0%	-4%	-9%	-12%	-15%	-20%
Reference S. 2191 (2)	$481	$524	$520	$552	$593	$672
High NG Tech (3)	0%	0%	0%	1%	1%	0%
High NG Tech High Elec (4)	0%	0%	-2%	-4%	-5%	-7%
High NG Tech Low Elec (5)	0%	0%	3%	2%	4%	9%
Low NG Tech (6)	0%	0%	0%	1%	1%	1%
Low NG Tech High Elec (7)	0%	0%	-2%	-3%	-5%	-5%
Low NG Tech Low Elec (8)	0%	0%	3%	3%	6%	15%
Low NG, Elec; No CCS, Nuc (9)	0%	0%	3%	3%	7%	15%
Low NG, Elec; No CCS, Nuc, Retrofits(9b)	0%	0%	6%	8%	12%	18%

Percent change in per capita average annual residential electricity costs relative to the reference scenario. Reference scenario, in gray, lists per capita average annual residential electricity costs in 2006 dollars.

In response to higher electricity prices, consumers can reduce their electricity demand by three different methods: conservation, increased efficiency, and substitution. Conservation simply means using less of something. For example, electricity customers could consume less electricity by turning off lights in unoccupied rooms or buying smaller appliances that use less electricity. A consumer can also invest in more energy efficient products that provide the same level of service but do so with lower electricity consumption. Examples of residential electrical efficiency include buying a more efficient appliance that provides the same level of service as another less efficient appliance or increasing the insulation in buildings. Increasing efficiency is not free. Higher efficiency products, including appliances, lighting, buildings, and equipment cost more than 'normal' efficiency products. Numerous studies have shown that electrical efficiency has a lifetime cost of about 3 cents per kilowatt-hour.[*] Substitution means using another energy source, for example natural gas or natural lighting, instead of electricity. An example of substitution is using natural gas, steam, or biomass (wood) for heating buildings instead of electricity. As a conservative approximation, we assume that all reduction in residential electricity use from 2008 is achieved through investment in efficiency at a cost of 3 cents per kWh, though in reality

[*] Three cents per kWh is the lifetime cost of avoided electricity purchases (measured as kWh purchases avoided). The EPA estimates that energy efficiency has a lifetime cost of 3 cents per kWh in its National Action Plan for Energy Efficiency. A recent Resources for the Future paper, Retrospective Examination of Demand-Side Energy Efficiency Policies, estimates that utility demand side management programs cost on average 3.4 cents per kWh of end use consumption avoided.

some of the demand reduction would be achieved through conservation at no additional cost. Assuming an electrical efficiency cost of 3 cents per kilowatt-hour, per capita residential annual electricity expenditures, including efficiency, increase slightly (Table 14) compared to annual electricity costs excluding efficiency spending (Table 13). This approximation likely overestimates residential expenditures on efficiency because it assumes consumers do not increase electricity conservation.

Table 14: Percent change in per capita annual residential electricity costs, including efficiency, from reference scenario (2).

	2008	2010	2015	2020	2025	2030
Business-as-usual - No carbon cap (1)	0%	-4%	-10%	-13%	-16%	-21%
Reference S. 2191 (2)	$481	$524	$527	$563	$606	$686
High NG Tech (3)	0%	0%	0%	1%	1%	0%
High NG Tech High Elec (4)	0%	0%	-2%	-4%	-6%	-7%
High NG Tech Low Elec (5)	0%	0%	3%	2%	4%	9%
Low NG Tech (6)	0%	0%	0%	1%	1%	1%
Low NG Tech High Elec (7)	0%	0%	-2%	-3%	-5%	-5%
Low NG Tech Low Elec (8)	0%	0%	3%	3%	6%	15%
Low NG, Elec; No CCS, Nuc (9)	0%	0%	3%	3%	8%	15%
Low NG, Elec; No CCS, Nuc, Retrofits(9b)	0%	0%	6%	8%	12%	18%

Percent change in per capita average annual residential electricity costs including the cost of efficiency relative to the reference scenario. Annual efficiency costs calculated as decrease in per capita residential electricity use relative to 2008, multiplied by 3 cents per kWh. Reference scenario, shaded in gray, lists per capita average annual residential electricity costs including the cost of efficiency in 2006 dollars.

7. Greenhouse Gas Emissions and Allowance Prices

7.1. Greenhouse gas emission allowance prices

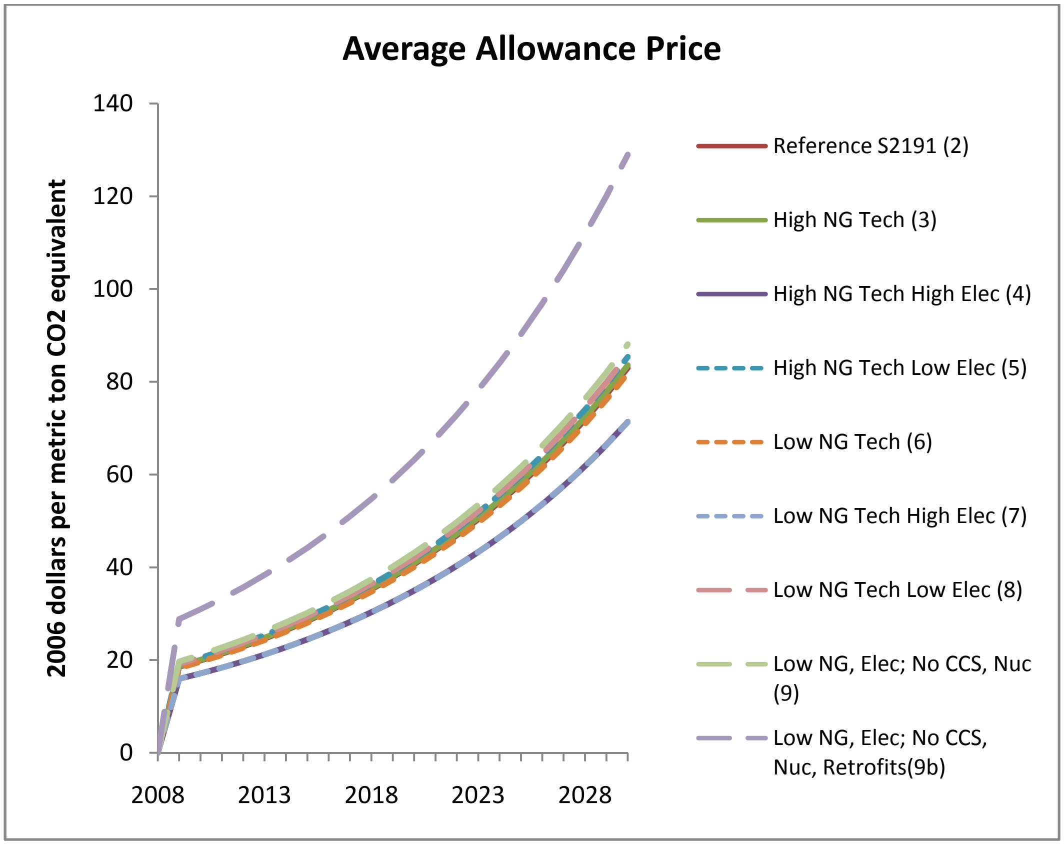
Average annual GHG emission allowance prices show little variation between scenarios with the exception of the most restricted technology scenario (9b) that does not allow for CCS retrofits of existing coal power plants and high electricity-sector development scenarios 4 and 7. As seen in Figure 26, the inability to retrofit existing power plants increases allowance prices 55%[*] compared to the reference case. Conversely, the high electricity-sector technology development (scenarios 4 and 7) decrease allowance prices 14% compared to the reference case.[†] Electricity sector technology development and CCS retrofit availability are key drivers of allowance prices as these factors determine the GHG intensity of the electricity sector.

Allowance price results do not exhibit large year-to-year variation and thus appear as smooth lines for two main reasons: allowance banking and foresight. S. 2191 allows GHG emission sources to reduce emissions beyond what is required and then bank these emissions reduction credits (allowances) for future years. This has the effect of enabling regulated emissions sources to spread the benefit of excess emissions reductions over multiple years. Foresight means that regulated emission sources know approximately how much they will need to reduce GHG emissions in the future and thus they can plan their expenditures to meet these reductions and spread the cost of these expenditures over time.

[*] The 55% price differential between the reference scenario and scenario 9b remains constant for all years after 2009

[†] The 14% price differential between the reference scenario and scenario 9b remains constant for all years after 2009

Figure 26: Annual average GHG emissions allowance price in 2006 dollars per metric ton of CO_2 equivalent.



7.2. Electricity sector GHG emissions

Total electricity sector CO_2 emissions and emissions from coal generation decrease significantly under a carbon cap (Figures 27 and 28).[*] Electricity sector emissions with a carbon cap are highest in 2030 for the most restricted technology scenario (9b) without CCS retrofits. This demonstrates that for all CCPP scenarios, utilities will continue to use coal as a generation source, albeit at lower levels, despite high allowance prices and high electricity-sector GHG emissions. Higher electricity-sector emission rates are possible because S. 2191 caps GHG emissions from most sectors of the economy and allows offsets of emissions from sources not regulated by S. 2191. If electricity sector emissions increase, emissions from other sources decrease as higher allowance prices make emissions reduction economical in other parts of the economy. For scenario 9b, higher electricity sector emissions are abated through increased use of offsets and lower emissions from the residential, commercial, transportation, and industrial sectors.[†]

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[*] The CCPP used emissions factors described in *Assumptions to the Annual Energy Outlook 2008* (http://www.eia.doe.gov/oiaf/archive/aeo08/assumption/index.html) for this modeling project.

[†] Residential, commercial, transportation, and industrial sector GHG emissions do not include emissions from the electricity consumed in each sector.

Figure 27: Annual electricity sector GHG emissions in million metric tons CO_2 equivalent.

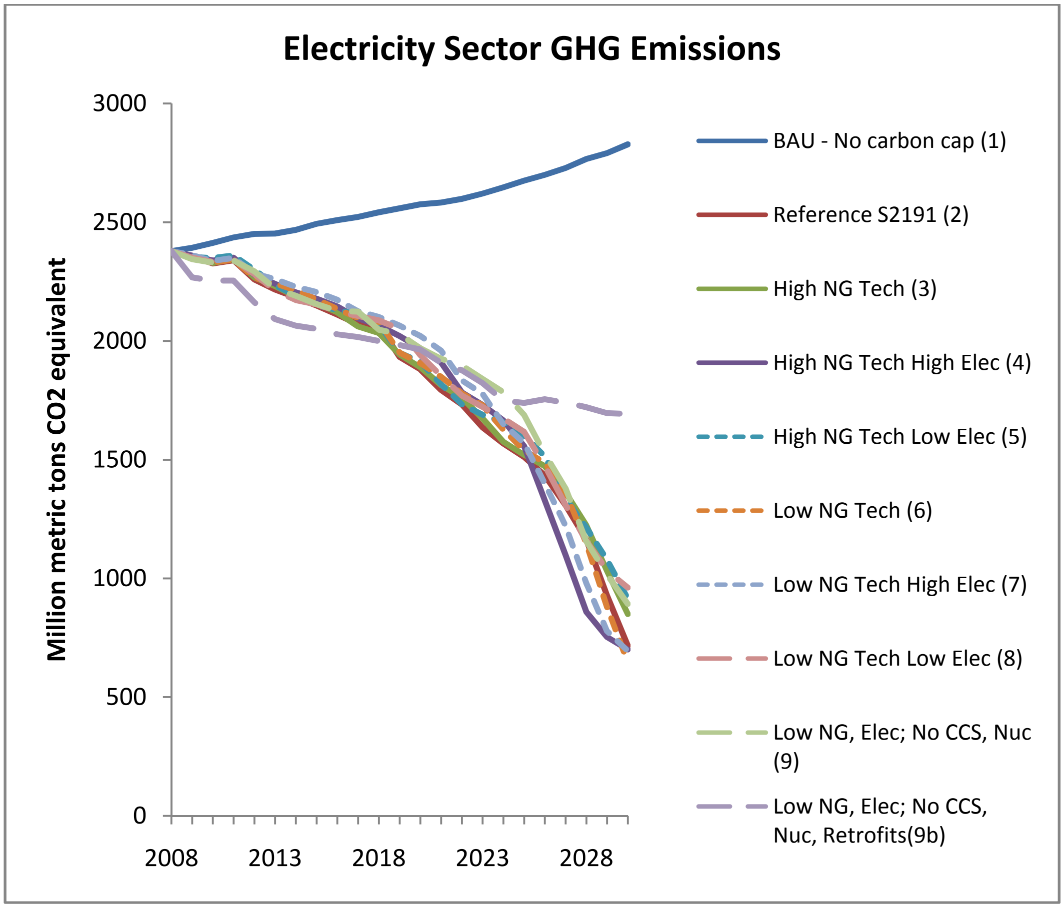
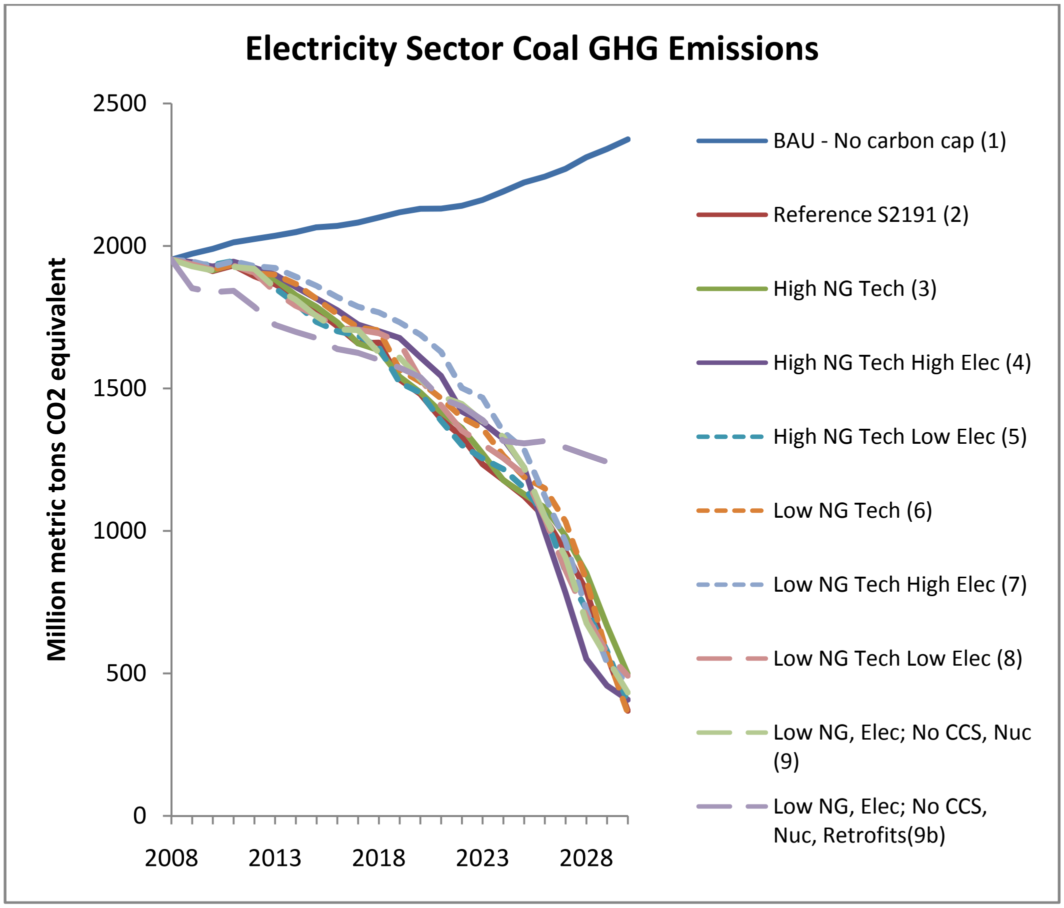


Figure 28. Annual electricity sector GHG emissions in million metric tons CO_2 equivalent.



8. Discussion

For all CCPP scenarios, natural gas does not replace coal as the primary baseload generation source in the United States. Thus, natural gas generation is not generally a substitute for coal baseload generation under the CCPP's scenarios used in this analysis. Comparing coal and natural gas capacity factors for all scenarios, coal capacity factors are approximately double natural gas capacity factors (Figure 29).

Higher capacity factors for coal demonstrates that coal plants remain first in the loading order despite a carbon cap. Coal is still used as a baseload generation source because utilities operate within the technical constraints of generating facilities and generally operate their lowest cost plants first in order to minimize costs. Baseload generation must produce a stable and predictable amount of electricity to meet baseload demand. Nuclear, large-scale hydro and coal generating facilities are best suited for baseload generation. Renewables such as wind or solar are less predictable generating sources best suited for intermediate electricity generation because of the intermittent supply of sun and wind. Natural gas, petroleum, and hydro[*] generating facilities are best suited for peak and intermediate demand because the facilities can easily alter electricity production to match demand requirements.

Although utilities do not make operating decisions based solely on fuel costs and variable operating costs, it is illustrative to compare costs for different fuels and generation facilities. Table 15, natural gas and coal fuel input costs including carbon, shows that fuel input costs for coal power plants per MMBtu, including the cost of carbon, are lower in all scenarios than for natural gas power plants. Variable operating costs account for differences in fuel price as well as differences in generation efficiency and other operating costs. Comparing the variable operating costs in 2006 cents per kWh (fuel costs plus variable operations and maintenance costs) of an existing pulverized coal plant and an existing natural gas combined cycle plant (Table 16), variable operating costs are lower for an existing pulverized coal plant through 2020 for most scenarios. CCPP estimated variable operating costs using weighted average heat rates for new pulverized coal and new natural gas combined cycle plants constructed between 2000 and 2006[†], variable operations and maintenance costs for new plants from the Annual Energy Outlook 2000[‡] and Table 15 fuel costs data; this approach is intended to represent a typical, recently constructed plant. Please note that variable cost estimates are dependent on heat rate data and other assumptions and are national average costs per year. Coal and natural gas prices vary by region and actual fuel input costs, especially natural gas fuel costs, can fluctuate significantly throughout the year. Actual operating decisions also depend on the current market-clearing price for electricity, which these tables do not take into account.

As a sensitivity analysis, CCPP conducted another variable operating costs comparison for new pulverized coal and natural gas combined cycles plants built in 2008 using Annual Energy Outlook 2008

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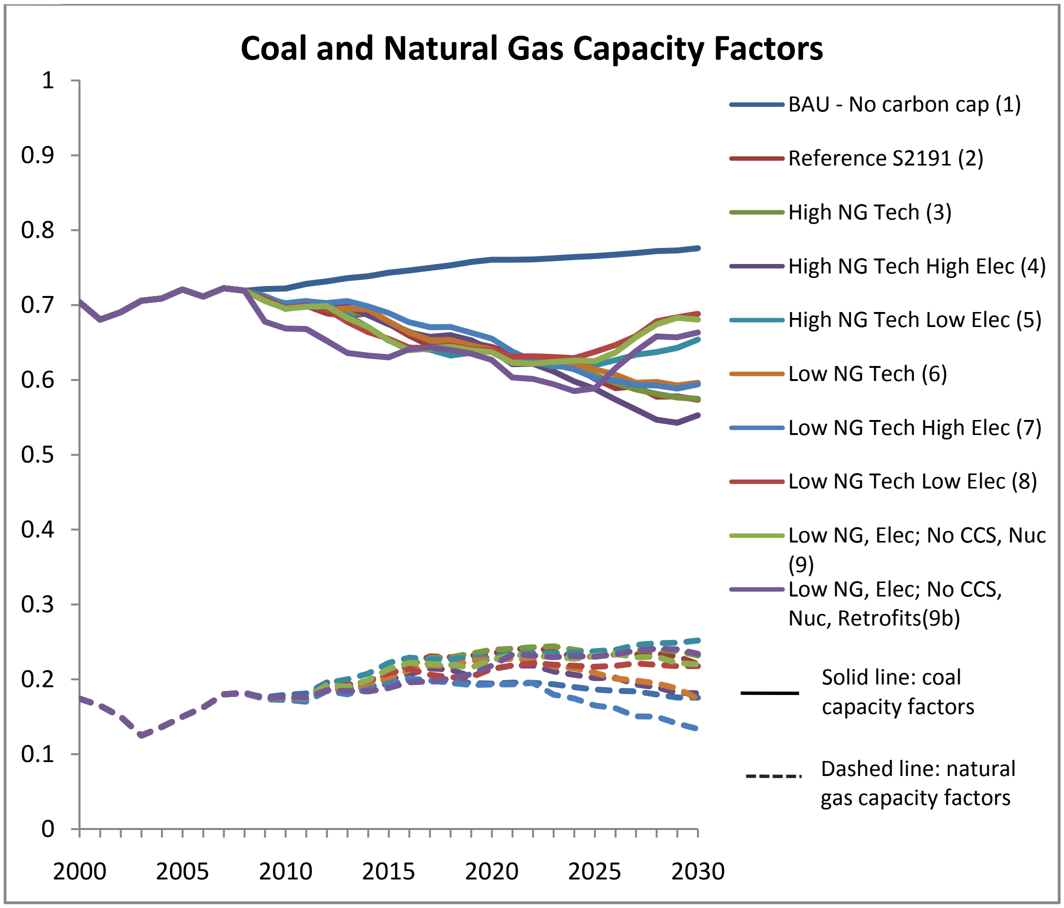
[*] Many areas of the country use hydropower for baseload generation.

[†] Heat rate data from EIA power plant database for new generation plants constructed from 2000–2006.

[‡] CCPP assumed that variable operations and maintenance costs increase 0.5% annually.

assumptions.* The results show lower variable costs for coal relative to natural gas than the primary analysis. For CCPP scenarios, NI-NEMS projects that at least 74% of coal generation capacity and 78% of natural gas capacity available in 2030 was in operation in 2008.

Figure29. Average coal and natural gas power plant capacity factors



* See Table 17a in Appendix A for EIA's 2007 new generation capacity heat rate assumptions. Please note that heat rate estimates change over time in NI-NEMS as generation technology improves.

Table 15: Coal and Natural Gas Fuel Input Costs 2006 $/MMBtu.

	2008	2010	2020	2030
Business-as-usual - No carbon cap (1)	1.77	1.84	1.69	1.75
	7.24	7.23	6.60	7.98
Reference S. 2191 (2)	1.77	1.83	5.53	9.55
	7.24	7.17	8.98	12.58
High NG Tech (3)	1.77	1.84	5.56	9.61
	7.24	7.17	9.05	12.82
High NG Tech High Elec (4)	1.77	1.84	4.98	8.44
	7.24	7.13	8.38	11.39
High NG Tech Low Elec (5)	1.77	1.84	5.66	9.84
	7.24	7.17	8.91	13.75
Low NG Tech (6)	1.77	1.83	5.49	9.47
	7.24	7.23	9.28	13.44
Low NG Tech High Elec (7)	1.77	1.84	4.99	8.48
	7.24	7.18	8.57	12.20
Low NG Tech Low Elec (8)	1.77	1.84	5.68	9.92
	7.24	7.24	9.30	15.80
Low NG, Elec; No CCS, Nuc (9)	1.77	1.83	5.78	10.14
	7.24	7.24	9.48	15.63
Low NG, Elec; No CCS, Nuc, Retrofits(9b)	1.77	1.82	7.66	13.93
	7.24	7.25	10.73	17.97

Blue cells show natural gas fuel input costs.
Gray cells show coal fuel input costs.

Table 16: Existing pulverized coal and natural gas combined cycle power plant fuel + variable O&M cost 2006 cents per kWh.

	2008	2010	2020	2030
Business-as-usual - No carbon cap (1)	2.22	2.29	2.16	2.24
	5.32	5.31	4.85	5.86
Reference S. 2191 (2)	2.22	2.28	6.10	***10.24***
	5.32	5.26	6.58	9.19
High NG Tech (3)	2.22	2.29	6.13	***10.30***
	5.32	5.26	6.63	9.36
High NG Tech High Elec (4)	2.22	2.29	5.53	***9.10***
	5.32	5.23	6.15	8.33
High NG Tech Low Elec (5)	2.22	2.29	6.23	***10.54***
	5.32	5.26	6.53	10.04
Low NG Tech (6)	2.22	2.29	6.05	***10.16***
	5.32	5.31	6.80	9.82
Low NG Tech High Elec (7)	2.22	2.29	5.54	***9.14***
	5.32	5.27	6.28	8.92
Low NG Tech Low Elec (8)	2.22	2.29	6.26	10.62
	5.32	5.31	6.81	11.53
Low NG, Elec; No CCS, Nuc (9)	2.22	2.29	6.36	10.85
	5.32	5.31	6.94	11.40
Low NG, Elec; No CCS, Nuc, Retrofits(9b)	2.21	2.28	***8.28***	***14.73***
	5.32	5.32	7.85	13.10

Gray cells show variable operating costs for a recently constructed pulverized coal plant.
Blue cells show variable operating costs for a recently constructed natural gas combined cycle plant.
Cells with ***bold italics*** indicate where coal is more expensive then natural gas.

As demonstrated in Figures 22, 23, and 24, the greatest variation in electricity generation by source occurs between natural gas and renewable generation. Coal generation is comparatively stable across the scenarios. Based on this variability and the fuel and variable operating cost advantage of coal compared to natural gas, it is evident that additional natural gas and renewable generation capacity are direct competitors and substitutes for one another more than they are competitors or substitutes for coal.

9. Conclusions

As expected, the S. 2191 carbon cap reduces total electricity demand and encourages the development of low GHG emission generation sources. Despite higher costs for fossil fuel power generation sources such as coal and natural gas, fossil fuels will continue to provide the largest share of the nation's electricity. Coal and nuclear power plants (existing plants) will continue to be the primary supply of baseload electricity generation in the United States. Contrary to many other predictions, a S. 2191 or similar carbon cap will not end the use of coal, even under the most pessimistic scenarios for future sequestration of carbon from coal power plants.

Electricity sector natural gas consumption could vary considerably in the future and may exceed consumption without a carbon cap. Future natural gas consumption will primarily be determined by the rate of development of other technologies, such as renewables generation and carbon capture and sequestration technology. The ability to capture and sequester carbon will have a large impact on delivered natural gas prices because the success of this technology will have significant impact on GHG emission allowance prices under a carbon cap. Regardless of technology development, it appears unlikely that natural gas will displace coal as a baseload generation source. If policymakers are concerned about the impact of climate change legislation on future natural gas prices, our modeling results suggest that policymakers should invest in CCS, CCS retrofits and renewable electricity generation research, development, demonstration and deployment. Future technology improvements and reduced costs in these two areas, especially CCS and CCS retrofits, will be critical to keeping future natural gas and electricity costs low under a carbon cap. Our results indicate that development in these areas will be more important than advancements in natural gas extraction technology.

Appendix A

Additional Tables and Figures

Table 17a. Comparison of EIA and CCPP overnight construction costs, EIA heatrate assumptions.

Overnight Cost $ 2006/kW Generation Capacity			
	EIA AEO 2008 ($ 2006)	CCPP 2008 ($ 2006)	Heatrate in 2007 (Btu/kWh)*
Scrubbed coal New	1,534	2,178	9,200
IGCC	1,773	2,525	8,765
IGCC w/ CO_2 seq	2,537	3,332	10,781
Conv Gas/Oil Comb Cycle	717	855	7,196
Adv Gas/Oil Comb Cycle (CC)	706	1,048	6,752
Adv CC w/CO_2 seq	1,409	1,854	8,613
Conv Combustion turbine	500	704	10,833
Adv Combustion turbine	473	794	9,289
Fuel Cells	5,374	5,495	7,930
Advanced Nuclear	2,475	4,928	10,400
Distributed Generation-Base	1,021	1,276	9,200
Distributed Generation-Peak	1,227	1,533	10,257
Biomass	2,809	2,872	8,911
MSW-Landfill gas	1,897	2,317	13,648
Geothermal	1,110	1,135	35,376
Conventional Hydropower	1,551	1,586	10,022
Wind	1,434	1,776	10,022
Wind Offshore	2,872	2,937	10,022
Solar Thermal	3,744	4,575	10,022
Photovoltaic	5,649	6,905	10,022

Sources: EIA Assumptions to the Annual Energy Outlook 2008, Table 38, IHS/CERA Power Capital Cost Index (http://www.ihsindexes.com/), Integrated Resource Plan for Connecticut January 2008 (http://www.brattle.com/_documents/UploadLibrary/Upload656.pdf).

*For hydro, wind, and solar technologies, the heatrate shown represents the average heatrate for conventional thermal generation as of 2006. This is used for the purposes of calculating primary energy consumption displaced for these resources, and does not imply an estimate of their actual energy conversion efficiency.

Figure 9a. Electricity sector natural gas consumption as a percentage of total U.S. natural gas demand.

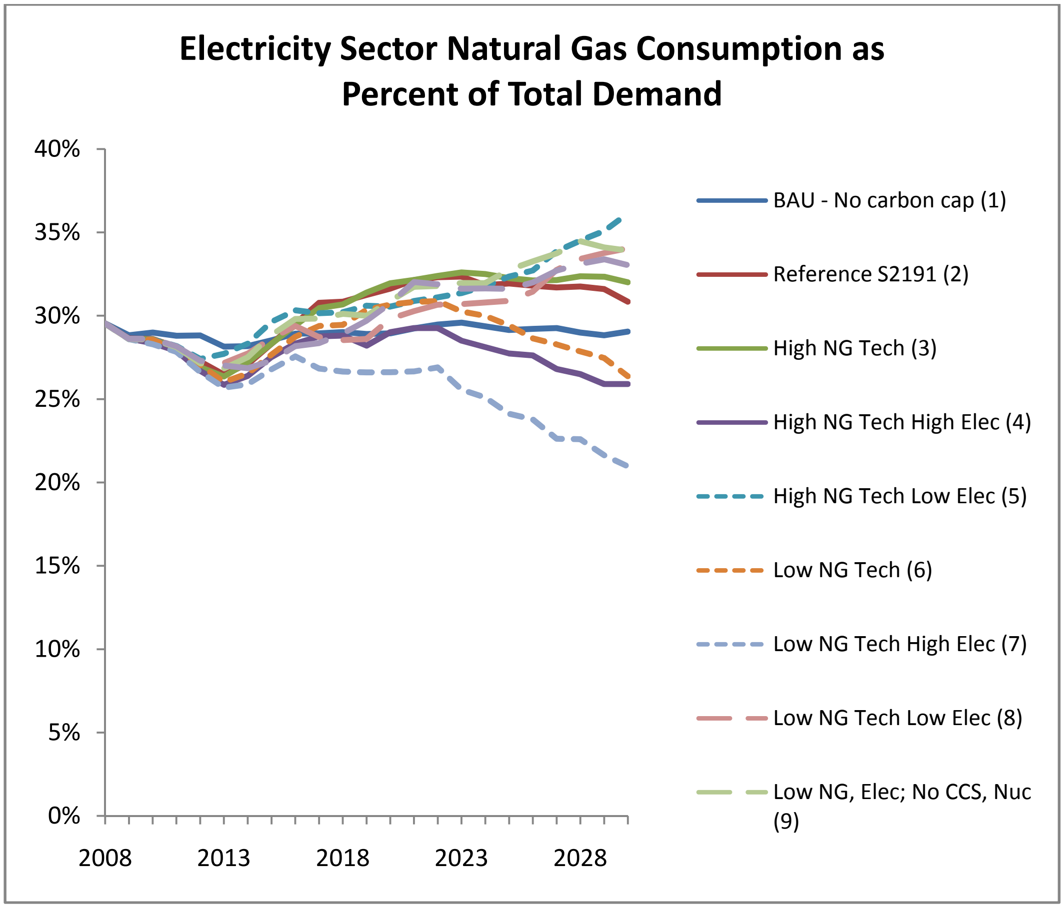
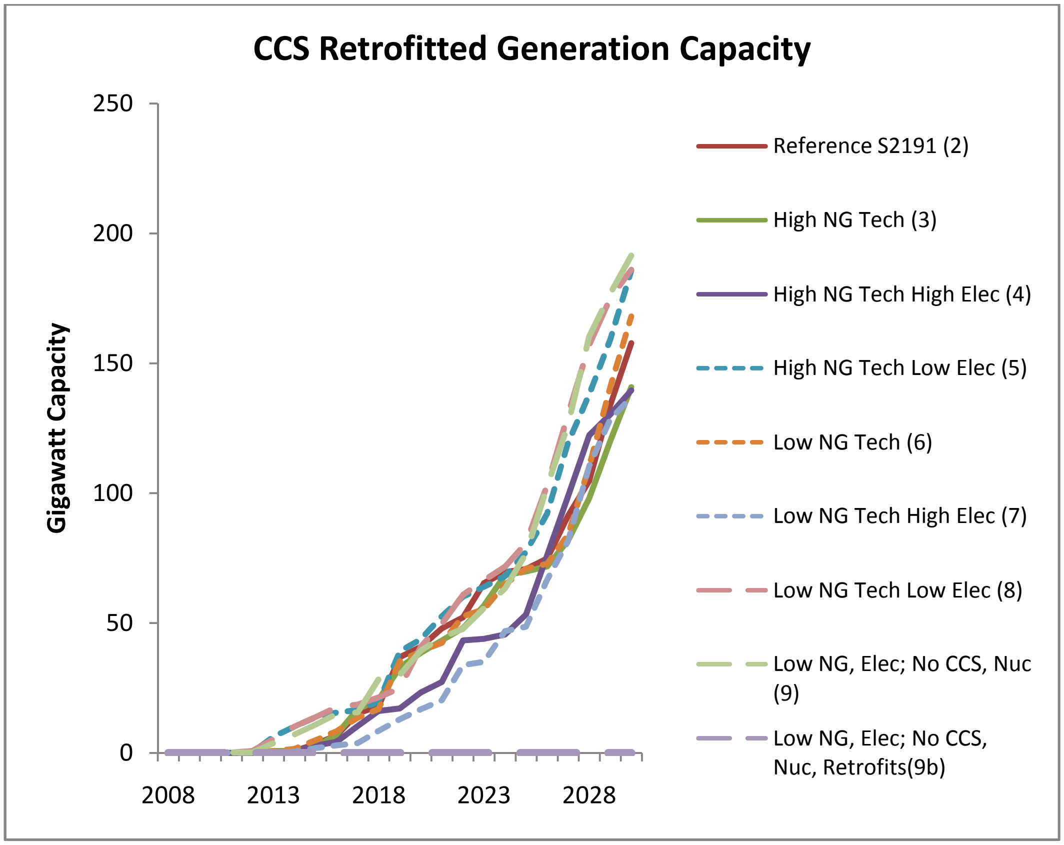


Figure 13a. Cumulative coal generation capacity retrofitted with carbon capture and storage capacity in gigawatts.



Appendix B

CCPP Assumptions for High and Low Natural Gas Extraction Technology Development Scenarios

Adjusted EIA Annual Energy Outlook (AEO) 2008 Assumed Annual Rates of Technological Progress (percent/year) for Conventional Crude Oil and Natural Gas Sources by + or – 75% over the reference case for

- finding rates
- drilling costs
- lease equipment costs
- operating costs
- success rates
- facility construction time
- facility construction costs
- initial production rate
- availability and development of technology for unconventional production

Increased unconventional natural gas reserves – All scenarios
Assumed Haynesville Shale, not included in AEO 2008 unconventional reserve base contains same reserves as Barnett Shale (likely conservative – USGS has not released updated reserve estimates for the Haynesville Shale)

LNG Import Assumptions (trillion cubic feet/year) – All scenarios

2008	0.9
2009	0.42
2010	0.44
2011	0.48
2012	0.51
2013	0.53
2014	0.56
2015	0.59
2016	0.62
2017	0.65
2018	0.69
2019	0.72
2020	0.74
2021	0.75
2022	0.76
2023	0.77

2024	0.79
2025	0.81
2026	0.83
2027	0.85
2028	0.86
2029	0.87
2030	0.88

CCPP Assumptions for High and Low Electricity-Sector Technology Development Scenarios

High Electricity Technology Scenarios
Decreased overnight price for all generation by 20%
Reduced the technology optimism factor—the tendency to underestimate the cost of new generation technologies—by 50%
Increasing learning factors by 50% for all generation except mature technologies
Learning factors are the rate at which the overnight cost decreases

Low Electricity-Sector Technology Development Scenarios
Increased overnight price for all generation by 50%
Increased the technology optimism factor—the tendency to underestimate the cost of new generation technologies—by 50%
Decreased learning factors by 50% for all generation except mature technologies

Restricted Technology Scenario
Changed technology availability date of IGCC, IGCC with sequestration, Advanced Gas Combined Cycle with sequestration, Nuclear and Advanced Nuclear to 2020

Restricted Technology Scenario b
Same as above with no possibility for retrofits throughout the simulation

Appendix C

Additional U.S. Natural Gas Supply and Demand Estimates

The federal government and numerous other institutions have published modeling based projections of future U.S. domestic natural gas production, demand, and import availability. Within the Federal government, the EIA has the primary responsibility of forecasting future domestic and international demand and supply of natural gas. The EIA released its Annual Energy Outlook 2008, in June of 2008.[*] The Baker Institute for Public Policy at Rice University released a report on North American natural gas markets and security in January 2008. The Energy Modeling Forum (EMF) at Stanford University released its 23rd study, *Prices and Trade in a Globalizing Natural Market*, in July 2007. Jensen Associates, a firm providing LNG market analysis, prepared a report for the California Energy Commission in August 2007 about potential LNG supplies available to the United States.[35] All of the included estimates were published prior to recent announcements of successful drilling of the Haynesville shale and do not include a federal carbon cap or tax.

EIA Annual Energy Outlook 2008

The Annual Energy Outlook 2008 contains a base reference case and additional cases modeling the impact of technology availability, restrictions on new generation capacity, construction cost variability, supply, and fossil-fuel supply constraints.[†] None of the scenarios include restrictions on GHG emissions. The 2008 Annual Energy Outlook forecasts differ from the 2007 Annual Energy Outlook due to lower projections of future U.S. economic growth, higher fuel prices, reduced projected energy demand and other factors. Table 18c shows the reference case demand, LNG imports, and Henry Hub prices. Total forecasted natural gas demand in 2020 is 10% less in the AEO 2008 than the AEO 2007 and 13% less in 2030.

[*] The EIA released the *Annual Energy Outlook 2009 Early Release* in January 2009. The full report was not available when this paper was made public.

[†] In total, the 2008 Annual Energy Outlook includes ten scenarios beyond the reference case that significantly or directly affect natural gas markets. For more information see the Annual Energy Outlook 2008, available from http://www.eia.doe.gov/oiaf/aeo/index.html

Table 18c: EIA Annual Energy Outlook 2008 natural gas demand, Henry Hub price, and LNG Imports.

	2007	2008	2009	2010	2015	2020	2025	2030
Total Demand (Tcf/year)	22.90	23.12	23.31	23.25	23.66	23.33	22.99	22.72
LNG Imports (Tcf/year)	0.74	0.90	0.99	1.20	2.12	2.37	2.60	2.84
Henry Hub Price (2006 dollar per MMBtu)	$6.78	$7.23	$7.35	$6.90	$5.87	$5.95	$6.39	$7.22

Tcf: trillion cubic feet
MMBtu: million Btu

Baker Institute Policy Report – Natural Gas in North America: Markets and Security

The Baker Institute conducted a two-year study examining natural gas markets in North America. The study focused on access to domestic natural gas resources, outlooks for growth in natural gas demand, the impact of growth in international LNG trade, and the price relationship between oil and natural gas. As part of the study, the Baker Institute developed its Baker Institute World Gas Trade Model using 2006 data as a baseline for its projections. The Baker Institute's report on its findings, *Natural Gas in North America: Markets and Security,* includes domestic natural gas production projections for two scenarios: 1) a business as usual scenario with continued restrictions on access to federal lands and the outer continental shelf for oil and gas exploration and 2) an unrestricted access scenario. Neither scenario considers impacts from proposed climate change legislation. Table 19c, below, shows the report's domestic natural gas production projections.[36] The report projects that U.S. natural gas demand will increase approximately 1.3% annually over the next 20 years to 26.9 Tcf per year in 2025. LNG imports are projected to rise significantly in the business as usual scenario to 8.8 Tcf per year in 2025 will while natural gas imports from Canada will decline significantly over the next 20 years as Canadian natural gas is increasingly used for tar sands oil production.[37]

Table 19c. Baker Institute Natural Gas in North America: Markets and Security.

Domestic Natural Gas Production

Scenario	2015	2025
Baseline: Business as Usual	20.8	21.1
Unlimited Access to Federal Resources	22.3	24.2

Units: Trillion cubic feet

Energy Modeling Forum Report 23: Prices and Trade in a Globalizing Natural Gas Market

The Energy Modeling Forum at Stanford University is a forum for energy experts, analysts, university faculty, private industry representatives, and policymakers from around the world to study energy issues. The Forum's *Report 23: Prices and Trade in a Globalizing Natural Gas Market* summarizes the forum's discussion of international gas market models. The report includes analysis of 11 different models using common input assumptions across the models. The models use the International Energy Agency's 2006 World Energy Outlook as a baseline. Seven models make projections about U.S. demand

and domestic production rates from 2005 to 2020. With the exception of two models, U.S. domestic production is projected to grow by 0.6% to 1.5% per year through 2020.[38] Table 20c shows projected U.S. domestic natural gas production, using the upper (1.5% per year) and lower (0.6% per year) bounds of the positive production growth models with year 2005 domestic production as a baseline.

Table 20c: Energy Modeling Forum projected U.S. domestic natural gas production.

Growth Rate	2005	2010	2015	2020
0.6% (low)	18.1	18.6	19.2	19.8
1.5% (high)	18.1	19.5	21.0	22.6

The seven models estimating future U.S. demand and domestic production project that U.S. LNG imports will grow on average 7% between 2005 and 2020 to 1.6 Tcf per year in 2020. All of the models making projections about U.S. natural gas demand and supply assume there will be a significant reduction in natural gas imports from Canada in the future. The Energy Modeling Forum's *Report 23* also concludes that failure to build individual LNG facilities should not significantly affect U.S. or European market supply and that higher global economic growth and higher global natural gas demand[*] will not cause large increases in the price of natural gas.[39]

Jensen Associates 2007 Report for the California Energy Commission

Jensen Associates, a LNG market analysis firm, prepared a report for the California Energy Commission about the future availability of LNG in the United States. The report includes three scenarios: an optimistic scenario based on prior forecasts that LNG liquefaction capacity will increase significantly as was widely believed a few years ago, a baseline scenario using conservative assumptions adopted by the EIA and the International Energy Agency, and a pessimistic scenario that accounts for the geopolitical issues associated with many producing countries such as Nigeria. Jensen Associates makes forecasts based on its database of all planned LNG liquefaction projects worldwide and then estimates the likelihood of construction for each project. Jensen Associates believes that its baseline scenario, with a growth rate of 6.7% a year until 2020, is the most likely to occur. Table 21c, below, shows Jensen's base, optimistic, and pessimistic scenario for liquefaction capacity in 2020.

[*] The Energy Modeling Forum's Higher World Demand Growth scenario assumes global GDP growth rates will increase 0.5% and global natural gas demand will increase 0.27% per annum relative to the reference scenario.

Table 21c: Jensen Database liquefaction capacities by project classification.

Project Classification	Bcfd
Operating YE 2006	24.1
Firm	10
Probable	9.5
Possible (Stated Schedule)	16.5
Possible (Unscheduled)	14.1
Total Potentially Available in 2020	74.2
Base	48.3
Optimistic	62.4
Pessimistic	40.9

Bcfd: billion cubic feet per day

Source: Jensen Associates

Appendix D: Biomass Supply and an Alternative Biomass Supply Scenario Analysis

Upon reviewing the modeling results, it became clear that biomass will likely play a major role in supplying the United States with electricity in the future under climate change legislation. Estimates of future biomass availability for energy production vary greatly, and the current NEMS assumptions fall within the range of availability (Table 22d). NEMS forestry residue supply data is from the U.S. Forest Service, and urban wood waste data is from state and regional agencies. Agricultural residue and energy crop supply data are from the University of Tennessee's POLYSIS model and increase over time, unlike urban wood waste and forestry residue.[40] The Milbrant report estimates the technical[*] biomass resources currently available in the United States.[41] The Walsh report also estimates currently available biomass resources and creates supply curves for biomass subcategories by state.[42] Perlack et al. estimate biomass supply in 2030 under multiple scenarios.[43] The Perlack values in Table 22d, moderate agricultural yield increase and high yield increase, are estimates of potential future biomass supply assuming moderate and high yield increases, improvements in harvest technology, increased residue to grains ratios and major land use changes.[44]

Table 22d: U.S. biomass supply by source.

	NEMS, 2008	Milbrandt 2005	Walsh et al. 1999	Perlack et al. 2005 - moderate ag yield increase	Perlack et al. 2005 - high ag yield increase
Urban Wood Waste	497	1,540	1,782	1,694	1,694
Forestry Residue	2,898	784	1,539	3,434	3,430
Agriculture Residue	2,725	2,198	2,110	5,964	8,680
Energy Crops	6,262	2,016	2,632	2,184	5,278
Total	***12,382***	***6,538***	***8,063***	***13,276***	***19,082***

U.S. biomass supply by source in trillion Btu. Assuming 7,000 Btu per lb of biomass as an estimate of the included range of fuels.

As a sensitivity analysis, the CCPP completed a scenario with the carbon cap reference case (scenario 2) and conservative biomass availability to reflect the estimates included in the Milbrant report. This supply is based on current biomass availability and assumes no increases in yields or improved harvest technology. Results from the scenario were compared to the reference case and are found in Table 22d, below.

[*] Technical resources are accessible biomass resources constrained by land use, local conditions, and other factors.

Prior to 2020, natural gas prices barely differ between the reference case and reference case with conservative biomass availability. Electricity generation from renewable resources decreases from 2020 to 2030 in the pessimistic biomass case relative to the reference case (Table 22d) because of the lower biomass availability. Natural gas electricity generation increases when biomass is constrained, but the natural gas generation does not make up the entire differential, as total electricity generation decreases and other generation sources increase in the conservative biomass scenario. The increased use of natural gas leads to an increase in Henry Hub spot prices after 2020. Throughout the modeling period, electricity sector natural gas consumption increases relative to the reference scenario. Total U.S. natural gas demand is more or less unchanged in the conservative biomass scenario. Allowance prices for GHG emissions decreases slightly when biomass is constrained and average electricity prices increase slightly, less than 1.5%.

In 2007, the EIA completed an analysis with NEMS on the potential energy market impacts of a 25% Renewable Fuels Standard and 25% Renewable Portfolio Standard by 2025.[45] In the analysis, the EIA found that biomass provides a significant portion of the new energy resources coming on line by 2025. Biomass electricity generation increased 363% in the EIA's policy case relative to their reference case in 2030.[46] The total biomass electricity generation from the EIA's analysis is greater than CCPP biomass electricity generation for all scenarios in 2025 but 6% lower than CCPP's reference scenario biomass electricity generation in 2030.[47]

Table 23d: Constrained biomass modeling results.

		2010	2015	2020	2025	2030
Henry Hub Spot Price (2006 $/MMBtu)	Reference Case	7.13	6.02	6.56	6.96	7.78
	Reference Case with Low Biomass Supply	7.12	6.07	6.54	7.22	8.27
Total Electricity Generation (terawatt hours)	Reference Case	3,935	3,953	4,015	4,078	4,159
	Reference Case with Low Biomass Supply	3,941	3,953	4,022	4,074	4,142
Natural Gas Electricity Generation (terawatt hours)	Reference Case	687	728	855	868	836
	Reference Case with Low Biomass Supply	690	738	854	928	967
Electricity Sector Natural Gas Consumption (Tcf)	Reference Case	6.63	6.58	7.66	7.70	7.36
	Reference Case with Low Biomass Supply	6.63	6.67	7.64	8.23	8.34
Total Renewable Electricity Generation (terawatt hours)	Reference Case	480	566	662	830	1,188
	Reference Case with Low Biomass Supply	489	571	648	750	906
Biomass Electricity Generation (terawatt hours)	Reference Case	103	164	195	326	673
	Reference Case with Low Biomass Supply	111	162	182	255	372
Average Electricity Price (2006 cents/kWh)	Reference Case	9.7	10.2	11.3	12.5	14.5
	Reference Case with Low Biomass Supply	9.7	10.1	11.2	12.6	14.7
U.S. Natural Gas Demand (Tcf)	Reference Case	23.2	23.2	24.2	24.1	23.9
	Reference Case with Low Biomass Supply	23.2	23.3	24.2	24.6	24.8
Allowance Price (2006 $/ton)	Reference Case	21.54	33.86	53.66	85.39	136.17
	Reference Case with Low Biomass Supply	20.99	33.00	52.29	83.21	132.69

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the Climate Change Policy Partnership

The Climate Change Policy Partnership (CCPP) researches carbon-mitigating technology, infrastructure, institutions and overall systems in order to inform lawmakers and business leaders as they lay the foundation of a low-carbon economy. Duke University's CCPP is an interdisciplinary research program of the Nicholas Institute for Environmental Policy Solutions, the Nicholas School of the Environment, and the Center on Global Change. Our corporate partners make our research possible and help us bridge the gap between academic research, business expertise, and effective climate change policy application.

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