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## Abstract

According to recent assessments, the United States has considerably more recoverable natural gas in shale formations than was previously thought. Such a development raises the possibility of a shift in U.S. energy consumption toward natural gas. To examine how the apparent abundance of natural gas might affect U.S. energy markets and the role of natural gas in climate policy, we model five scenarios—reflecting different perspectives on natural gas availability, the availability of competing resources, and climate policy—through 2030. We find that more abundant natural gas supplies result in greater natural gas use in most sectors of the economy. We further find that natural gas could serve as a bridge fuel to a low-carbon future, but only if appropriate low-carbon policies are in place.

**Key Words:** natural gas markets, shale gas resources, climate policy, energy policy

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## Contents

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## 1. Introduction

Recent assessments suggest that the United States has considerably more recoverable natural gas in shale formations than was previously thought, as new drilling technologies dramatically lowered recovery costs. The apparent abundance of natural gas raises the possibility of a substantial shift in U.S. energy consumption toward natural gas. At the same time, many are looking to natural gas as a bridge fuel to a low-carbon future because its use yields carbon dioxide ($CO_2$) emissions that are about 45 percent lower per British thermal unit (Btu) than coal and 30 percent lower than oil. Such a transition seems particularly attractive in the electric power sector if natural gas were to displace coal.

The possibility of more abundant natural gas raises a number of questions that we seek to answer in the present exercise. How might more abundant natural gas affect the fuel mix? Will it create a market-driven reduction in $CO_2$ emissions? Does it lower the cost of policies to reduce $CO_2$ emissions? Some ancillary questions are: What are the implications for natural gas use when nuclear and renewable power generation are limited? How is natural gas use affected if a renewable portfolio standard is used in conjunction with a cap-and-trade system?

To assess how the apparent abundance of natural gas might affect U.S. energy markets and the role of natural gas in climate policy, we compare five scenarios that reflect different perspectives on natural gas availability, the availability of competing resources, and climate policy. We modeled these scenarios, which run through 2030, using NEMS-RFF.[1] The scenarios

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[1] The National Energy Modeling System (NEMS) is a computer-based, energy-economy market equilibrium modeling system for the United States developed by the U.S. Department of Energy. NEMS-RFF is a version of NEMS developed by Resources for the Future (RFF) in cooperation with OnLocation, Inc. NEMS-RFF projects market-clearing prices and quantities across a number of energy markets, subject to assumptions about macroeconomic and financial developments, world energy market conditions, demographics, resource availability

reflect different perspectives on natural gas resources in shale formations, the adoption of low-carbon policies, and the availability of nuclear and renewable power generation.

By comparing these scenarios, we assess how the relative abundance of natural gas might affect its consumption and its potential to reduce $CO_2$ emissions. We find that more abundant natural gas supplies result in greater natural gas use in most sectors of the economy. More importantly, we find that with appropriate carbon policies in place—such as a cap-and-trade system or a carbon tax—natural gas can play a role as a bridge fuel to a low-carbon future. The role of natural gas as a transition fuel to a low-carbon future could be enhanced if the use of nuclear and renewable power proves to be limited, or it could be reduced if renewable portfolio standards are used to supplement cap-and-trade policies.

Nonetheless, we find that having low-carbon policies in place is essential if natural gas is to serve as a bridge to a low-carbon future. Without such policies, more abundant natural gas does not reduce $CO_2$ emissions. Although greater natural gas resources reduce the price of natural gas and displace the use of coal and oil, they also boost overall energy consumption and reduce the use of nuclear and renewable energy sources for electric power generation. As a result, projected $CO_2$ emissions are almost 1 percent higher.

With a carbon cap-and-trade system in place, however, we find that greater natural gas supplies can help meet carbon-reduction goals. With more abundant natural gas, the use of natural gas in electricity generation increases significantly and overall natural gas consumption remains robust, which lessens slightly the burden on other measures to reduce $CO_2$ emissions. In addition, the price of $CO_2$ allowances falls slightly, which lessens the economic cost of reducing $CO_2$ emissions somewhat. It is this ability to lower the costs of climate policy that makes natural gas an attractive bridge fuel to a low-carbon future.

From a broader perspective, however, our analysis suggests that the most cost-effective means for reducing $CO_2$ emissions depends greatly on projected resource availability and technology changes, both of which are highly uncertain. If policymakers are to develop meaningful and cost-effective policies for controlling $CO_2$ emissions, they must develop policies that are robust across different projected futures.

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and costs, the cost and performance characteristics of energy technologies, and behavioral and technological choice criteria.

## 2. U.S. Natural Gas Markets

Natural gas is used widely throughout the U.S. economy—in industry, residences and commercial establishments, and to generate electric power. About 90 percent of U.S. natural gas consumption is met by domestic production. The remainder is imported from Canada or from other countries as liquefied natural gas (LNG). Increased production from shale formations is expected to reduce reliance on LNG imports in future years. Throughout the United States, a substantial system of pipelines connects natural gas producers with their consumers.

### *2.1 Natural Gas Consumption*

Natural gas plays an important role in U.S. energy use. It accounted for nearly 25 percent of total U.S. energy consumption in 2008. Only petroleum product consumption accounted for more (Figure 1). In contrast with oil and coal (the use of which are concentrated in transportation and electric power, respectively), natural gas is used across a variety of sectors in the U.S. economy (Figure 2). The industrial sector is the largest user, accounting for nearly 35 percent of total natural gas consumption.[2] The electric power sector accounts for nearly 30 percent. The residential sector is the second-largest end-use sector, accounting for more than 20 percent of total natural gas consumption. Natural gas is also used in the commercial sector, and a small amount of natural gas is used in the transportation sector.[3]

The use of natural gas to generate electric power increased sharply in the late 1990s and early 2000s. The growth was driven by changes in regulation, new technology, relatively abundant natural gas, lower capital costs relative to those for coal and nuclear power plants, and environmental advantages over coal and oil. As the electric power sector was restructured, some regulatory advantages for natural gas use in power generation were eliminated. Those developments led to idle generation capacity and weaker-than-anticipated growth in natural gas use in the electric power sector.

Owing to its use for space heating and in peaking plants for electric power generation, the demand for natural gas is highly seasonal and weather related. The seasonal peak occurs during the winter months, but spikes occur when there is a strong demand for winter heating or summer air conditioning, with the latter supplied by natural gas–fired electricity. The seasonal and

[2] This figure includes lease and plant fuel.

[3] This figure includes natural gas used as a fuel for pipelines used in its own transportation.

weather-related swings in consumption are met by natural gas in storage. Natural gas production and imports are relatively steady throughout the year. In a typical year, natural gas is put into storage over the summer months from late spring to late fall and is withdrawn over the winter months from late fall to early spring.

### *2.2 Natural Gas Supply*

As shown in Figure 3, U.S. natural gas supplies come from a variety of sources, including domestic production, imports through pipelines from Canada, and LNG from a number of countries.[4] Currently, almost 99 percent of U.S. gas consumption comes from domestic sources and Canada. Under baseline projections from NEMS-RFF, which were made with conservative assumptions about shale gas resources, that percentage is expected to fall to slightly less than 97 percent in 2030 as the United States imports more LNG.[5]

Over the same time horizon, U.S. natural gas production is expected to continue a transition to unconventional sources, such as tight sands, shale, and coalbed methane. Arctic production sites in Alaska and Canada's Mackenzie Delta are also thought to be important future sources of North American natural gas. In the more distant future, coalbed methane and gas hydrates may contribute significant shares of U.S. natural gas production.

A recent study by the National Petroleum Council (NPC; 2007) and the *Annual Energy Outlook 2009* produced by the Energy Information Agency (EIA) both underscore the likely transition in North American natural gas production over the next 20-plus years. According to NPC, the production of natural gas from conventional resources in the lower 48 states will decline while production from unconventional resources in the lower 48, resources in the Arctic (such as Alaska and Canada's Mackenzie Delta), and/or imports of LNG will increase. EIA expects that unconventional sources of natural gas will account for more than half of U.S. production by 2030.

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[4] LNG is produced by cooling normally gaseous methane to about –260°F. In this liquid form, methane takes up 1/600th of the space and can be shipped from one location in the world to another. On the receiving side, it can be shipped to its destination in special trucks or regasified and added to the pipeline grid.

[5] The United States also exports natural gas to Mexico, and that is projected to continue under all of the scenarios examined.

### *2.3 Natural Gas Resources in Shale Formations*

The impact of shale gas resources on the U.S. market could be more substantial than these projections show. In its *Annual Energy Outlook 2009*, EIA placed U.S. shale resources at 269.3 trillion cubic feet with total U.S. natural gas resources of 1,759.5 trillion cubic feet. In contrast, Navigant Consulting (2008) finds that U.S. shale gas resources could be as high as 842 trillion cubic feet, and the Potential Gas Committee (PGC; 2009) provides an estimate of 615.9 trillion cubic feet. As shown in Figure 4, these shale gas resources are widely distributed throughout the United States.

Despite the substantially higher estimates of shale gas resources, the likely supply profiles remain highly uncertain because the industry has relatively little experience in producing natural gas from such formations. In addition, the U.S. Environmental Protection Agency (EPA) is taking steps toward regulating the hydraulic fluids that have been important to enhancing the production of shale gas and boosting the estimates of recoverable resources from shale gas formations (Obey 2009). Industry sources variously say that EPA regulation could have no effect, could slightly increase the cost of shale gas production, or could completely shut it down.

### *2.4 Natural Gas Infrastructure*

As shown in Figure 5, a substantial transmission and distribution system connects natural gas producers with their customers. Natural gas produced at the wellhead, known as *wet gas*, contains a mixture of hydrocarbons and impurities. Wet gas is typically consolidated in a collection system. At that point, natural gas processing plants remove impurities and other hydrocarbons so that nearly pure methane ($CH_4$) is obtained.[6]

The processed gas, known as *dry gas*, is moved from the producing fields to market in natural gas pipelines. Most of the larger customers, such as electric utilities and industry, are served directly by pipelines. Residential and commercial customers who use relatively small quantities of natural gas are served by local distribution companies, which are themselves served by the pipelines.

LNG, another source of natural gas for the United States, is imported in special ships through eight terminals on the East Coast and along the Gulf of Mexico (Table 1). At these

[6] The hydrocarbons removed include propane and butane, which are typically sold as part of the petroleum product chain.

terminals, regasification facilities return the LNG to a gaseous state and inject it into the pipeline system. Together, the existing terminals offer a capacity of 4.2 trillion cubic feet annually, nearly 20 percent of current U.S. consumption.

### *2.5 Alaskan Natural Gas and Pipeline*

Alaska is a potential source of natural gas in North America. PGC (2009) estimates that Alaska has 193 trillion cubic feet of natural gas resources, accounting for about 18 percent of conventional, non-shale natural gas resources in the United States. Obviously, a pipeline needs to be built from the potential producing regions in Alaska to the lower 48 if these natural gas resources are to reach a sizable U.S. market.

A number of competing proposals are being considered. The TransCanada and ExxonMobil consortium are proposing a pipeline (Figure 6) that would extend some 1,700 miles from Alaska to connections in Alberta. To reach markets in the lower 48, the Alaska natural gas would need to travel as much as an additional 1,500 miles using existing or new pipelines. The BP and ConocoPhillips consortium is considering a route through Yukon and British Columbia along the Alaska Highway and then to Alberta. Other proposed routes include moving the natural gas across Alaska to an LNG export terminal in Valdez and through the Mackenzie River Valley in the Northwest Territory. The latter route is attractive because it could also serve natural gas production in the Mackenzie Delta, another potentially large source of Arctic natural gas (Figure 7).

## 3. How NEMS-RFF Represents U.S. Natural Gas Markets

To evaluate the effects of more abundant natural gas from shale deposits, we use NEMS-RFF. The National Energy Modeling System (NEMS) is a computer-based, energy-economy market equilibrium modeling system for the United States developed by the U.S. Department of Energy. NEMS-RFF is a version of NEMS developed by Resources for the Future (RFF) in cooperation with OnLocation, Inc. NEMS-RFF projects market-clearing prices and quantities across a number of energy markets, subject to assumptions about macroeconomic and financial developments, world energy market conditions, demographics, resource availability and costs, cost and performance characteristics of energy technologies, and behavioral and technological choice criteria.

NEMS-RFF consists of a set of models (or modules) that represent energy supply and demand for all fuels and all demand sectors in the U.S. economy. In NEMS-RFF, all major fuel supply markets, conversion sectors, and end-use sectors of the energy system are represented, as are macroeconomic activity and links to international markets. The system represents energy end-use markets for the residential, commercial, industrial, and transportation sectors with 12 regions in the United States, 2 in Canada, and 1 in Mexico.[7] Electric power generation is represented as a conversion sector using natural gas and other energy sources to provide electricity to the four end-use sectors.[8]

### *3.1 Natural Gas Supply and Demand*

The natural gas market is represented as a market-clearing relationship established between the modules representing natural gas demand and those representing natural gas supply. The demand side includes modules for the residential, commercial, industrial, and transportation sectors and electric power generation. The supply side includes an oil and natural gas supply module, a petroleum market module, and an international energy module. Natural gas consumption and production are linked through a natural gas transmission and distribution module. The demand modules are driven in part by a macroeconomic activity module.

Together, the modules use 11 key drivers to establish market-clearing prices and quantities for U.S. natural gas markets in every year through 2030. The demand side includes macroeconomic activity, such as industrial output; population growth; prices for competing fuels and technologies; technological progress, learning curves, and cost improvements; capital investment and retirement rates for existing capital stock; and consumer choice preferences and hurdle rates of return. The supply side includes ultimate recoverable resources and finding rates; natural gas supply and demand in Canada; supply curves of LNG; and trigger prices for new major pipelines and LNG regasification terminals.

The model reflects normal energy market dynamics in which the short-run responses to changes in price are much weaker than the long-term responses. On the supply side, short-run production decisions are largely dominated by existing reserves, though production-to-reserve

[7] The United States is divided into extended census divisions that include the normal census regions in addition to splits between the South Atlantic region and Florida; the Mountain region and Arizona/New Mexico; and the Pacific region with California, Alaska, and Hawaii each handled separately.

[8] The electricity sector is treated as an end-use sector for natural gas demand.

ratios will rise with prices. Over the long run, producers have the time to develop resources into reserves and then production, which accounts for the stronger long-run response.[9]

NEMS-RFF has a detailed bottom-up representation of oil and natural gas production in North America. Exploration, development, and production costs in individual producing regions are the major determinants of the U.S. domestic supply of natural gas. Trends in these costs are projected with historical data. Higher prices stimulate production by increasing production from existing fields and through increased investment in more costly areas. Changes in tax policy, incentives, and resource accessibility also affect natural gas investment and production.

On the demand side, the differences between short-run and long-run responses are largely achieved by linking energy choices to the existing capital stock. In the short run, natural gas consumption is dominated by such factors as the existing stock of equipment, heating and cooling degree days, and economic activity. As existing capital stock is retired and new investment reshapes the capital stock, end users are more able to change the composition and quantity of their energy consumption.

The electric power sector is modeled purely on the basis of cost minimization. Consequently, the sector shows considerable flexibility in fuel choices, and it responds readily to changes in fuel prices. In the residential, commercial, industrial, and transportation sectors, however, NEMS-RFF explicitly models the technology choice process. In these sectors, the use of natural gas is very unresponsive to the differential between natural gas prices and those for other fuels, even in the long run.

The lack of response in the residential and commercial sectors results from those modules severely limiting consumer choices. For replacement equipment, the choice of fuel is primarily determined by the fuel that was used in the equipment being retired. For residential housing, the same-fuel share is 95 percent. This restriction may reflect the view that choice is curtailed by the lack of the necessary natural gas distribution systems in regions that are not currently served very well by natural gas.

The lack of response in the industrial sector is the result of the corresponding module showing that nearly every facility that can switch to natural gas from another fuel has done so the

[9] Resource exhaustion imposes no limits on U.S. natural gas production over the time horizon of the model. At current U.S. natural gas production levels, the initial gas resource estimates plus the additional shale resources estimated by the PGC would last another 100 years.

lack of response in the transportation sector is the result of that module lacking any economic determinants in substituting compressed natural gas (CNG) or LNG for diesel fuel in long-haul trucking or CNG for gasoline in auto transportation.

### *3.2 Natural Gas Transmission and Distribution*

To complete the North American natural gas market in NEMS-RFF, the Natural Gas Transmission and Distribution Module simulates the natural gas flows between the 15 regions in the United States, Canada, and Mexico, meeting the demand of the five consumption sectors in all U.S. regions while taking into account restrictions in the transmission and distribution networks. Supplies, flows, and delivered prices are determined in a low-demand and a high-demand period. Pipeline tariffs have two parts: a fixed reservation charge and an operational usage fee.

New interregional pipeline capacity is built as the costs can be recovered in later years.[10] Under the model's tariff structure, little excess capacity is built and pipeline capacity constraints can affect consumption during periods of high natural gas demand.

## 4. Assessing the Implications of More Abundant Natural Gas

To assess how more abundant natural gas might affect energy markets, $CO_2$ emissions, and the role of natural gas as a bridge fuel to a low-carbon future, we compare five scenarios developed with NEMS-RFF that reflect different perspectives on natural gas availability, climate policy, and the availability of competing resources. Two of these scenarios are business-as-usual (BAU) cases that assume that the United States adopts no new policies to reduce $CO_2$ emissions. The first scenario uses what now seem to be conservative estimates of shale gas resources of 269.3 trillion cubic feet that date from 2007, but were used recently in EIA's *Annual Energy Outlook 2009*. The second uses newer, more optimistic estimates of 615.9 trillion cubic feet developed by PGC (2009).[11]

[10] Investments along major new pipeline routes, such as those from Alaska and the Canadian Mackenzie Delta, occur after a sufficiently high natural gas price is reached in the lower 48 states to justify the investment. As a result of restrictions placed on the model, the Alaskan pipeline can be built at earliest in 2020, the Mackenzie pipeline in 2014 at earliest. Expansions of these pipelines can occur after an additional increase in gas prices.

[11] EIA has released its preliminary *Annual Energy Outlook 2010*, which places shale resources between the estimates used for *Annual Energy Outlook 2009* and those of PGC. In contrast, Navigant Consulting (2008) offers a mean estimate of 274 trillion cubic feet with a maximum of 842 trillion cubic feet.

The third and fourth scenarios are policy scenarios and are used to examine how different assumptions about natural gas resources affect the implementation of a low-carbon policy. Both assume that the United States adopts a cap-and-trade policy with $CO_2$ emissions targets similar to those in the American Clean Energy and Security Act (H.R. 2454), proposed by Representatives Henry Waxman and Edward Markey, and to those proposed by the Obama administration prior to the U.N. climate conference in Copenhagen. Like the first scenario, Scenario 3 uses conservative estimates of U.S. shale resources of natural gas. Scenario 4 uses the more optimistic estimates. A comparison of these scenarios with the first two allows us to assess how important enhanced natural gas supplies may be to the development of climate policy.

The fifth scenario examines how the use of natural gas fares under a low-carbon policy when recourse to nuclear and renewable power is limited or more costly. It is built on Scenario 4 but further assumes that the use of nuclear power is limited and that renewable energy sources have higher costs. The comparison of this scenario with the second and fourth allows us to assess the extent to which abundant natural gas or conservation might be used meet climate policy objectives when recourse to nuclear and renewable power generation is limited.

### *4.1 The Baseline Case (Scenario 1)*

The baseline scenario (Scenario 1) represents business as usual.[12] It is based on EIA's *Annual Energy Outlook 2009* as revised in April 2009 to include energy provisions in the stimulus package. It also advances the implementation of more stringent corporate average fuel economy standards from 2020 to 2016, as required by an Obama executive order issued in May 2009. Following estimates from *Annual Energy Outlook 2009*, the baseline scenario assumes U.S. shale natural gas resources of 269.3 trillion cubic feet with total U.S. natural gas resources of 1,759.5 trillion cubic feet.

U.S. natural gas consumption is projected to grow insignificantly from 2008 to 2030 under Scenario 1. Moreover, the projection shows natural gas consumption falling through 2014, particularly in electricity generation because recent changes in regulatory actions are expected to result in renewable energy, coal, and nuclear power continuing to crowd out natural gas. After 2014, the adjustment to regulatory change is mostly complete, and the electric power sector shows increasing use of natural gas.

[12] This scenario is identified as Core 1 in Krupnick et al. (2010), which is considered the master report for the RFF study in which the present exercise is included.

### *4.2 Implications of Abundant Natural Gas Supply (Scenario 2)*

EIA's estimates of U.S. natural gas supplies in *Annual Energy Outlook 2009* date from 2007. Given recent technological changes in extracting natural gas from shale deposits through hydraulic fracturing, the cost of recovering natural gas from shale formations has dropped significantly. In addition, more natural gas is recoverable. Reflecting these developments, PGC estimates U.S. shale gas resources at 615.9 trillion cubic feet. PGC estimates are carefully researched and well documented, and previous PGC estimates have been used in EIA analyses.

The second scenario is identical to the first, except that it substitutes the PGC estimates for U.S. shale gas resources. It assumes that more natural gas can be produced from each well. This approach yields both lower production costs and increased shale gas resources, with total U.S. natural gas resources boosted to 2,106.1 trillion cubic feet.[13]

Together, Scenarios 1 and 2 offer a wide range of plausible estimates for shale gas resources and reflect the considerable uncertainty about the supply or production profiles from shale gas formations. With this change, U.S. natural gas production is much stronger than in Scenario 1 (Figure 8). U.S. natural gas production shows only a mild decline from 2009 to 2014, with steady gains coming after that. With additional natural gas supplies, natural gas prices are lower—with the sharpest differences projected after 2025 (Figure 9). By 2030, the projections show Henry Hub natural gas prices more than 20 percent lower than in Scenario 1 (falling from $8.81 per million Btu to $6.86).[14] Lower natural gas prices delay the development of a natural gas pipeline from Alaska to the lower 48 states by three years and lead to 1.0 trillion cubic feet less offshore production in 2030. Even with such secondary effects, the responsiveness of U.S. natural gas production to changes in price is considerably greater.[15]

With more abundant supply, natural gas consumption is sharply higher than in Scenario 1. The biggest difference in natural gas use between Scenarios 1 and 2 is found in the electric power sector, where natural gas consumption is 22.5 percent higher (Table 2). Most of the gains

[13] The more conservative approach of increasing basin size or areas would capture increased resources but not reduced costs.

[14] Near New Orleans, Henry Hub handles the highest volume of natural gas of any U.S. transportation node and is close to the largest concentration of natural gas producing regions in the country. Henry Hub is a commonly used pricing point for natural gas in the United States, and its price movements are highly correlated with the NYMEX futures price, which is the most widely traded natural gas contract in the world.

[15] The model's implied supply elasticity for 2030 increases from 0.27 to 0.93.

in natural gas use in the electric power sector come from substitution for other energy sources (Figure 10). Some of the gains come from slightly increased electricity use brought about by lower electricity prices.

Perhaps surprisingly, enhanced natural gas supplies yield nearly 1 percent higher $CO_2$ emissions in 2030 compared with Scenario 1. Lower natural gas prices leads natural gas to displace coal, which reduces $CO_2$ emissions, but lower prices also encourage the displacement of some zero-carbon (nuclear and renewable) electric power sources. In addition, complex market interactions reduce projected prices for other energy resources and boost total energy consumption (by a little more than 1 percent in 2030). Together, these energy market changes increase $CO_2$ emissions. These findings suggest that greater shale gas resources by themselves do not lead the market toward reduced $CO_2$ emissions.

### *4.3 How Natural Gas Supply Affects Carbon Policy*

The third and fourth scenarios represent a cap-and-trade policy without and with enhanced natural gas resources, respectively. The $CO_2$ emissions targets are similar to those in H.R. 2454, but with only one billion metric tons in offsets instead of two billion.[16]

#### 4.3.1 Low-Carbon Policy without Abundant Natural Gas (Scenario 3)

Scenario 3 shows the effects of adopting a low-carbon policy without abundant natural gas resources.[17] As shown in Figure 11, this scenario shows reduced U.S. natural gas consumption compared to Scenario 1. Coal and oil use are also reduced, but substantial increases are found in nuclear and renewable power generation. Overall energy consumption is 5.4 percent lower in 2030, with electric power generation 8.2 percent lower. Energy consumption is lower in all sectors of the economy, and $CO_2$ emissions in 2030 fall from 6.2 billion tons in Scenario 1 to 4.8 billion tons in Scenario 3.

In 2030, U.S. natural gas consumption is 1.7 trillion cubic feet (7.1 percent) lower than in Scenario 1. For the same year, domestic natural gas production is 1.6 trillion cubic feet (7.0 percent) less. Imports are reduced slightly. As shown in Table 3, natural gas consumption is

[16] Offsets are emissions reductions achieved outside the sectors covered by the cap-and-trade program, either domestically or internationally. Proposed legislation would allow regulated entities to purchase offsets as an alternative to reducing emissions.

[17] Scenario 3 is the same as the central cap-and-trade policy (Core 2) discussed in Krupnick et al. (2010).

lower in all major sectors of the economy. The biggest reduction in natural gas use is in the electric power sector, where both natural gas and coal are displaced by conservation and gains in nuclear and renewable power generation (Figure 12).

### 4.3.2 Low-Carbon Policy with Abundant Natural Gas (Scenario 4)

With abundant natural gas supplies (Scenarios 2 and 4), the implementation of a cap-and-trade program yields a greater overall reduction in energy use than would occur without abundant supplies (Scenarios 1 and 3). Because greater natural gas supplies foster higher overall energy consumption and higher $CO_2$ emissions in the absence of policy intervention, bigger reductions in energy use are required to meet the $CO_2$ emissions targets (about 4.8 billion tons in 2030). Nonetheless, a comparison of Scenario 4 with Scenario 2 shows that natural gas production and consumption are only slightly reduced by the introduction of a low-carbon policy when natural gas supplies are abundant (Figure 13).

In the process, the use of natural gas for electric power generation rises, although its use falls in other sectors (Table 4). The opportunities for fuel switching between natural gas and other fuels are not quite as plentiful in residential, commercial, and industrial sectors (which together account for about 65 percent of natural gas use), so emissions reductions in these sectors depend more heavily on energy conservation. Consequently, implementation of a low-carbon policy reduces natural gas consumption in these sectors.

With abundant natural gas supplies, the share of natural gas in electric power generation in 2030 rises from 23.9 to 27.8 percent when the low-carbon policy is implemented (Figure 14). In contrast, without additional shale gas resources, the same low-carbon policy yields a *decline* in the share of natural gas in electric power generation, from 19.4 percent to 18.8 percent (Table 5). With more abundant, less expensive natural gas supplies, power generation from nuclear and renewable sources loses some advantages, and the use of coal falls by more.

In short, plentiful natural gas supplies mean that policies to reduce $CO_2$ emissions will yield a market-driven substitution of natural gas for other fuels in the electric power sector. In other sectors, which show limited substitution possibilities between natural gas and other energy sources, plentiful natural gas supplies do not have much effect on the means to reduce $CO_2$ emissions.

### 4.3.3 How Abundant Natural Gas AffectsLow-Carbon Policy

Beyond its greater use in electric power generation, the importance of abundant natural gas to a low-carbon policy is found through a comparison of the prices for the carbon allowances under the various scenarios. The price of the carbon allowance rises from $18.61 per metric ton of carbon in 2012 to $67.26 in 2030 under Scenario 3.[18] Under Scenario 4, the price of the carbon allowance is slightly lower, rising from $18.49 per metric ton of carbon in 2012 to $66.83 in 2030. The lower allowance prices translate into an avoidance of costs to the economy that amounts to about $30 million in 2012 and rises to about $300 million in 2030. Overall, welfare gains are modest over the period for which policy is modeled (2012–2030)—about $1 billion in present discounted value terms.[19]

In short, abundant natural gas creates a bridge to a low-carbon future under a cap-and-trade system that is not supplemented with a renewable portfolio standard or other government mandates. As Table 6 shows, the combination of abundant natural gas and a cap-and-trade system yields more natural gas consumption than is found under the baseline scenario that reflects neither abundant natural gas nor a cap-and-trade system. Economic theory suggests that other carbon-pricing systems, such as carbon taxes, would yield substantially similar results.

### *4.4 Limits on Nuclear and Renewable Power Generation (Scenario 5)*

As reported by Weyant (2009), the Energy Modeling Forum 22 (EMF 22), a bi-annual conference representing the work of 18 energy-modeling teams, is in the process of examining the effects of climate change mitigation policies on energy use. The study generally finds that natural gas is an important fuel under U.S. policies to sharply reduce $CO_2$ emissions by 2050. Several factors drive the increased use of natural gas in the EMF 22 projections for the United States. Through the increased use of electric and plug-in hybrid vehicles, electric power displaces petroleum in the transportation sector, which increases overall electricity consumption and the potential for natural gas use in electric power generation. In addition, the use of nuclear and renewable power generation is constrained in the EMF 22 analysis, which increases reliance on natural gas in the power sector to meet overall $CO_2$ emissions standards.

With abundant natural gas, we find that a policy to reduce $CO_2$ emissions yields results similar to those of the EMF 22 study for natural gas consumption but through somewhat different avenues. Clearly, part of the difference is the time horizon used for analysis. In our fourth scenario, plug-in hybrids penetrate only slightly into new automobile sales by 2030, which

[18] These prices and all others are in 2007 dollars.

[19] Discounted to 2010 using an interest rate of 5 percent.

contributes to a very slight shift toward electricity use in the transportation sector—but not by nearly as much the EMF 22 study shows for 2050. In addition, none of our four scenarios limits the use of renewable power generation, and the 50-gigawatt limit we placed on additions to nuclear power capacity might be seen as too optimistic for 2030, even though it is nonbinding in Scenario 4.

Scenario 5 is designed to more thoroughly examine how limiting the deployment of nuclear and renewable power generation might affect the role of natural gas in climate change policy. The scenario is constructed by modifying Scenario 4. A limit of 30 gigawatts is placed on additions to nuclear power and the growth rate of renewable power generation is restricted.[20] These methods of restricting capacity did not affect the cost of each technology.

As shown in Figure 15, limits on nuclear and renewable power yield higher natural gas use than is projected under either Scenario 2 or 4. Scenario 5 amplifies much of what is found in Scenario 4. Increased natural gas use in the electric power sector boosts the price of natural gas and yields reductions in natural gas use in other sectors (Table 7). In contrast to Scenario 4, however, the net effect is increased natural gas consumption over Scenario 2.[21]

As expected, nuclear and renewable energy play smaller roles in the electric power sector (Figure 16). Perhaps surprisingly, the use of coal to produce electricity is also reduced. When zero-emissions technologies are less available, it becomes more difficult to meet emissions targets. Cheap and dirty coal is disadvantaged by the reduced availability of zero-emissions technologies, and its use must be reduced. The advantage shifts to moderately clean but more expensive fuels, such as natural gas.

### *4.5 The Incidence of Low-Carbon Policy*

The question of who bears the costs often drives policy. In our particular case, the questions focus on which side of the natural gas market bears the costs of low-carbon policies,

[20] We also assume that the use of carbon capture and sequestration (CCS) is limited to the two gigawatts found under Scenario 4. This assumption is made to prevent NEMS-RFF from shifting toward CCS when we assume tighter restrictions on nuclear power and increased costs for renewable power generation.

[21] The limits on nuclear and renewable power and CCS used in Scenario 5 also increase somewhat the estimated costs of compliance with the cap-and-trade policy over that found with Scenario 4. Under Scenario 5, the price of the carbon allowance rises from $20.28 per metric ton of carbon in 2012 to $73.32 in 2030. For Scenario 4, the comparable prices are $18.49 and $66.83 for 2012 and 2030, respectively. These differences reflect the higher costs of reducing $CO_2$ emissions when technology is less available.

and the extent to which more abundant natural gas resources alter the incidence of a low-carbon policy.

Comparisons of the projected price paths with and without carbon policies reveal who bears the costs of the policies. The extent to which producers and natural gas users downstream bear the costs can be determined by comparing the natural gas prices they face under the carbon policy to those they face without the carbon policy in place. With the carbon policy in place, producers see a reduction in the Henry Hub price of natural gas. Downstream natural gas users pay the Henry Hub price plus the costs of the necessary $CO_2$ emissions allowances.

As shown by a comparison of Scenarios 1 and 3 in Figure 17, the cost of a carbon policy is shared almost equally between the natural gas producers and those using natural gas downstream from Henry Hub when natural gas resources in shale formations are not assumed to be abundant. Under Scenario 1, the price of natural gas at Henry Hub is $8.81 per million Btu in 2030. Under Scenario 3, the price of natural gas at Henry Hub is $7.99 per million Btu at Henry Hub in 2030 and $10.05 per million Btu when the cost of the $CO_2$ emissions allowances is added.[22]

When shale gas resources are assumed to be abundant, however, the cost of the carbon policy is shifted away from producers and toward those using natural gas downstream from Henry Hub, as is shown by a comparison of Scenarios 2 and 4. Under Scenario 2, the price of natural gas at Henry Hub is $6.86 per million Btu at Henry Hub in 2030. Under Scenario 4, the price of natural gas at Henry Hub is $6.67 per million Btu at Henry Hub in 2030 and $8.71 per million Btu when the cost of the $CO_2$ emissions allowances is added. The difference in the incidence of the carbon policy owes to the greater implied elasticity of natural gas supply that is found when shale gas resources are assumed to be more abundant.[23]

Evaluating the incidence of carbon policy by comparing the differences between Scenarios 1 and 3 on one hand and Scenarios 2 and 4 on the other may not provide a complete picture. Those using natural gas downstream from Henry Hub do absorb a greater share of the costs of a low-carbon policy when natural gas is more abundant, but the price paid for natural gas

[22] We use EIA's average $CO_2$ emissions factors for natural gas to apply the allowance.

[23] In general, the incidence of policies affecting natural gas markets depends on the elasticities of natural gas demand and supply. The greater the elasticity of demand, the less the cost of the policy will be borne by those who use natural gas. The greater the elasticity of supply, the less the cost of the policy will be borne by natural gas producers.

plus the $CO_2$ emissions allowances is lower than when natural gas is less abundant. Abundant natural gas simply makes the price of natural gas lower, and that dominates the results.

### *4.6 The Potential Effects of Intervening Mandates*

None of the scenarios we examine consider the use of mandates that favor a specific technology, but Böhringer and Rosendahl (2009) and Palmer and Sweeney (2010) show that the addition of a renewable portfolio standard to a cap-and-trade system can substantially alter market outcomes and increase costs. Both efforts find that the addition of mandates for such zero-emissions energy sources to a cap-and-trade system can disadvantage natural gas in favor of a combination of the cleanest and dirtiest technologies.

The Palmer and Sweeney work can be compared directly to ours because their study is part of the same group of studies in which the present exercise is included. It uses NEMS-RFF to examine the addition of a renewable portfolio standard in the electric power sector to a cap-and-trade system for $CO_2$ emissions. One of their scenarios adds a renewable portfolio standard in the electric power sector to what we identify here as Scenario 3, a case with a cap-and-trade policy and low estimates of the natural gas resource base.

Palmer and Sweeney find that the addition of a renewable portfolio standard in the electric power sector to an economy-wide cap-and-trade program reduces U.S. natural gas consumption. As might be expected, natural gas consumption is reduced only in electric power generation. A slight reduction in natural gas prices pushes up natural gas consumption in the other major sectors. The net effect is a reduction in natural gas consumption.

Palmer and Sweeney also find that the addition of a renewable portfolio standard to a cap-and-trade program has very little effect on the use of coal to generate electricity. In contrast, Böhringer and Rosendahl find that the use of a renewable portfolio standard in conjunction with a cap-and-trade program increases coal use relative to that under a cap-and-trade program alone. These differences may owe to differing responses to prices between the models and/or the scale at which the programs are implemented.

Because the supply of natural gas is considerably more elastic under the scenarios with more abundant shale gas resources, the addition of a renewable portfolio standard to a cap-and-trade program is likely to show more dramatic effects on natural gas use under an abundant shale gas scenario. Such a response also could lead to an increase in the use of coal for electric power generation in comparison to that found with a cap-and-trade program alone.

Although Böhringer and Rosendahl and Palmer and Sweeney reach slightly different conclusions about the use of coal, their findings point in similar directions. Driven by mandates rather than pricing, zero-emissions technologies no longer face market competition from moderately clean fuels. To the extent that goals for $CO_2$ emissions are achieved through the mandated use of clean and costly technologies, the use of cheap and dirty technologies need not be reduced by as much. The end result is a combination of mandates and market incentives that disadvantage natural gas and yield higher overall costs for a given reduction in $CO_2$ emissions. If mandates are unavoidable, it may be best to design them broadly to include a wide range of options for reducing $CO_2$ emissions.

## 5. Some Potential Issues with NEMS-RFF

The use of NEMS-RFF to assess the effects of more abundant shale gas resources raises a number of potential issues about the robustness of the model's projections. Prominent among such issues is the pricing of natural gas and petroleum products and the potential for fuel switching between these fuels. Additional possible issues include pipeline capacity for the transportation of natural gas, the development of a pipeline from Alaska to the lower 48 states, potential LNG exports from Alaska, and the adequacy of U.S. LNG import terminals.

### *5.1 Fuel Substitution and Natural Gas and Crude Oil Prices*

A small body of research with recent contributions by Villar and Joutz (2006), Brown and Yücel (2008b), and Hartley et al. (2008) shows that natural gas prices have moved with oil prices over the long run, probably as a result of interfuel substitution between natural gas and petroleum products. Short-run deviations in natural gas prices from the long-run relationship with crude oil prices is the result of seasonal variation, weather, production disruptions, deviations of natural gas inventories from the normal seasonal pattern, and other factors. As these intervening factors return to normal, however, the price of natural gas follows an error-correction process in which the price of natural gas gradually adjusts toward its long-run relationship with that for crude oil.

As Figure 18 shows, several of the different methods suggested by Brown and Yücel (2008b) for relating natural gas prices to those for crude oil show that the two prices have moved together historically. These methods include Brown and Yücel's econometric estimates of the long-run relationship between natural gas and crude oil prices, and two rules of thumb that Brown and Yücel report are used in the oil patch. Under these rules of thumb, the expected price of natural gas is obtained by dividing the price of crude oil by either 6 or 10.

In contrast with the historical relationship, the baseline scenario developed with NEMS-RFF shows projected natural gas prices that are well below that suggested by the crude oil prices projected in the baseline. In addition, the baseline case shows U.S. natural gas consumption moderating through 2014.

At issue with these projections are the potential for competition between natural gas and refined products and the projected growth of the U.S. industrial sector. An examination of NEMS-RFF shows that most of the potential for natural gas substitution for other fuels in the model occurs in the electric power sector where very little oil is used. In contrast, most oil is used in the transportation sector where very little natural gas is used. Only the industrial sector shows considerable consumption of both natural gas and petroleum products, and NEMS-RFF suggests that little opportunity exists for substitution between natural gas and petroleum products in the industrial sector. Moreover, the baseline NEMS-RFF projections show the U.S. industrial sector continuing to shrink in importance. Over the 2008 to 2030 time horizon, the model projects that U.S. gross domestic product (GDP) will grow at an annual rate of 2.45 percent per year from 2008 to 2030 while the industrial sector grows at a slower rate of 1.37 percent per year.

In contrast with the lack of response that NEMS-RFF shows, Huntington (2007) finds that natural gas consumption in the industrial sector is sensitive to differentials with petroleum product and crude oil prices over the long run. An important part of the fuel switching between natural gas and petroleum products occurs in the planning process when firms are determining which fuel would be preferable to use. Similar issues may be important in the commercial and residential sectors, where natural gas might be substituted for heating oil if additional natural gas infrastructure were developed.

The combination of projected slow growth in the industrial sector and the relatively weak substitution between natural gas and petroleum products in the industrial sector likely contributes to the weak growth of natural gas consumption found in the baseline case. From a policy perspective, the most important consequence of projections for slow growth in natural gas use is likely to be the potential effects on LNG imports.

From the point of view of understanding how more abundant natural gas supplies might affect the U.S. energy mix and policies to reduce $CO_2$ emissions, the lack of sensitivity in the industrial, residential, and commercial sectors of the NEMS-RFF model to differentials between natural gas prices and those for petroleum products may be an important issue.[24] If the potential substitution of natural gas for petroleum products is greater than is assumed in NEMS-RFF, natural gas prices could be considerably higher than the model projects, and the effects of enhanced natural gas availability on U.S. energy markets could be much more profound than our analysis shows.

### *5.2 Potential for Bottlenecks in Natural Gas Pipelines*

Brown and Yücel (2008a) show that capacity constraints in the U.S. interstate pipeline system have affected natural gas price differentials between various regions of the country. The NEMS-RFF model allows pipeline capacity constraints to emerge between interregional natural gas markets. In the model, pipelines cannot collect a congestion fee, but regional price differentials do reflect pipeline capacity constraints when they occur.

Without probing the model to determine the extent to which pipeline constraints play a role in the projections, it is difficult to assess how well the model reflects these market realities. To the extent that the model fails to capture the full extent of congestion, it could lead to more optimistic projections of natural gas use than are warranted. This issue may be important under any of the scenarios that show rapid growth in the use of natural gas, as is shown in Scenario 5.

### *5.3 Alaska Natural Gas Production*

Depending on which scenario is examined, the NEMS-RFF model shows a natural gas pipeline from Alaska to the lower 48 beginning operations as early as 2021 or as late as 2025.[25] The earlier date is associated with Scenario 3, which incorporates more conservative estimates of shale gas resources and a policy to restrict carbon emissions. The later date is associated with Scenario 2, which incorporates more optimistic estimates of shale gas resources and no policy to restrict carbon emissions.

The outcomes in NEMS-RFF assume that the decision to build the pipeline depend strictly on the economics of North American natural gas markets. In contrast, the various

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[24] Greater flexibility in the model with respect to technology and fuel choice when equipment is retired and replaced would yield much stronger responses to price differentials and greater energy efficiency in response to higher energy prices in the industrial, residential, and commercial sectors. (See Section 3.1 above.)

[25] Constraints on the model to limit the earliest potential date for the Alaskan pipeline to 2020 do not appear to be binding.

competing proposals to build pipelines from Alaska are subject to a political approval process, which is barely underway for one proposed pipeline. Moreover, one of the proposals would result in Alaska natural gas being exported to Asia as LNG. And if natural gas remains priced at par with oil in Japan (as is the current practice), analysis with the World Gas Model shows that the combination of world oil prices and North American natural gas prices projected with NEMS-RFF makes the export of Alaska natural gas the most attractive option.

Delays in pipeline development or the redirection of Alaska natural gas to the export market would reduce natural gas availability in the U.S. lower 48 market in the 2020s. Such a development would increase the price of natural gas in the lower 48 market and make natural gas less available as a bridge fuel to a low-carbon future. Failure to take into account the possibility of U.S. natural gas exports should be considered quite a limitation of the NEMS-RFF model.

### *5.4 Adequacy of U.S. LNG Import Terminals*

Currently, the United States has eight LNG import terminals with a total capacity of 4.2 trillion cubic feet per year. The Federal Energy Regulatory Commission lists another six terminals in the United States that have been approved and are under construction that would add another 2.9 trillion cubic feet in annual capacity and one in Canada that would add 0.4 trillion cubic feet. Another 14 terminals have been approved. Relative to the projected LNG imports, which reach a height of 1.42 trillion cubic feet in 2018 under Scenario 1, more than adequate LNG import capacity seems to be available.

### *5.5 The Adequacy of NEMS-RFF*

Of the issues we examined for NEMS-RFF, the projected growth of the industrial sector, the substitution between natural gas and petroleum products in the industrial sector, and the potential for U.S. exports of LNG all may make the modeling framework less than ideal for examining how more abundant natural gas might affect U.S. energy markets.[26] Pipeline congestion is a lesser issue, and the adequacy of LNG import facilities does not appear to be an issue over the projected time horizon.

[26] Some other models better capture natural gas market issues but without examining the complete energy system in which natural gas is used. (See Appendix B.)

## 6. Uncertainties about U.S. Natural Gas Markets

In examining natural gas markets, a number of issues not explicitly considered in our analysis may arise. Such issues include uncertainty about shale gas resources, the possible elimination of oil and gas tax preferences, potential changes in access to moratoria lands in which natural gas production is currently limited, the potential for increased production of coalbed methane, and the potential availability of gas hydrates. All of these issues affect the uncertainty about the outlook for U.S. natural gas markets.

### *6.1 Shale Gas Uncertainty and the Transition to a Low-Carbon Future*

The extent of shale gas resources and their likely supply profiles remain highly uncertain. In addition, EPA is taking steps toward regulating the hydraulic fluids that have been important to enhancing the production of shale gas and boosting the estimates of recoverable resources from shale gas formations (Obey 2009). This uncertainty about shale gas resources and their potential development has important implications for policy.

Some policies—such as those mandating the use of specific technologies—require accurate predictions about future resource availability and require technology change to be cost-effective. Policies that provide carbon pricing—such as cap-and-trade systems or carbon taxes—do not. With pricing, market participants have an incentive to seek out the most cost-effective means for reducing $CO_2$ emissions, which makes such policies robust across different projected scenarios. As the result of the considerable uncertainty about shale gas supplies, the adoption of specific policies that favor or disfavor natural gas could prove to be out of touch with market realities.

### *6.2 Elimination of Oil and Gas Tax Preferences*

The Obama administration has proposed the elimination of what it identifies as oil and gas company tax preferences (Office of Management and Budget 2009; U.S. Department of Treasury 2009). The elimination of such preferences is consistent with an agreement reached at the September 2009 G-20 summit in Pittsburgh for all G-20 countries to eliminate fossil fuel subsidies (G-20 2009). Our analysis does not address this policy change, but Allaire and Brown (2009) explain that these tax preferences account for less than 1 percent of oil and gas revenue and show that eliminating the tax preferences would have relatively small effects on U.S. natural gas markets.

According to Allaire and Brown, the elimination of the tax preferences would boost consumer prices for natural gas 2.0 cents per million Btu in 2011 and 4.1 cents in 2030. At the same time, producer prices would see reductions of 3.2 cents and 4.3 cents below baseline in 2011 and 2030, respectively. These price changes are relatively small when compared to the projected prices for 2011 and 2030, which are $5.48 per million Btu in 2011 and $8.81 in 2030, respectively.

Allaire and Brown also estimate correspondingly small changes in market quantities. They estimate that U.S. natural gas consumption will fall by 3 billion cubic feet below baseline in 2011 and 49 billion cubic feet per year in 2030. They also estimate that domestic natural gas production will fall 11 billion cubic feet below baseline in 2011 and 51 billion cubic feet in 2030. Natural gas imports will rise 7 billion cubic feet above baseline in 2011 and 2 billion cubic feet in 2030. These quantities are relatively small in comparison to the projected consumption figures for 2011 and 2030, which are 22.1 trillion cubic feet and 24.1 trillion cubic feet, respectively.

### *6.3 Moratoria Lands*

For the United States, current estimates of recoverable natural gas resources are 1,760–2,100 trillion cubic feet. Of this amount, about 162 trillion cubic feet is beneath federal lands on which drilling has been restricted or off limits. These restricted areas are found in Alaska, the Rocky Mountains, the Gulf Coast, and Appalachia.

In addition, another 92 trillion cubic feet of offshore natural gas resources are unavailable for development, including 86 trillion cubic feet in the federal outer continental shelf (OCS) moratoria regions. The OCS numbers are subject to considerable uncertainty because estimates for some of the areas were made 25–40 years ago (NPC 2007). The estimates could be increased with new exploration and assessments taking into account modern drilling and extraction techniques.

In general, one would expect that increased access to these areas formerly excluded from exploration and development would boost U.S. natural gas supplies. Such an effect is likely to be stronger in the scenarios with higher natural gas prices because exploration and production costs are generally higher in the moratoria lands. Consequently, one might expect that increased access to moratoria lands would reduce some of the uncertainty about U.S. natural gas supplies.

### *6.4 Coalbed Methane*

Coalbed methane is another unconventional natural gas source, and engineering advances in dewatering coal seams have boosted production since the 1990s (NPC 2007). As a result, coalbed methane contributed 2.0 trillion cubic feet to U.S. natural gas production in 2008 (EIA

2009). Scenario 1 projects annual production of coalbed methane varying from 1.6 to 2.0 trillion cubic feet from 2009 to 2030, and NEMS-RFF shows production of this unconventional resource to be price sensitive. Obviously, improved technology for coalbed methane would increase the availability of natural gas in U.S. markets. For now, it is probably safe to ignore the possibility of such technology changes.

### *6.5 Gas Hydrates*

Gas hydrates represent another unconventional natural gas resource, but unlike coalbed methane, gas hydrates are not yet in production. Gas hydrates are crystalline solids consisting of gas molecules, usually methane, each surrounded by a cage of water molecules. They have physical properties similar to ice and are found under permafrost in Arctic regions and near the seafloor on continental slopes and in deep seas and lakes. Resource assessments suggest that gas hydrates may be more plentiful than all other carbon fuels combined, but future production technology and costs are extremely uncertain. A substantial reduction in the costs of producing gas hydrates could increase the availability of natural gas in markets worldwide. For now it is probably safe to ignore the possibility of such technology changes.

### *6.6 Canadian Exports*

The Canadian and U.S. natural gas markets are intertwined, with Canada a net exporter of natural gas to the United States. The links between these two countries affects the uncertainty in the outlook for U.S. natural gas markets. The potential for Canada to boost its natural gas production reduces the uncertainty of the U.S. supply.

Canada has a large potential production area, the Mackenzie Delta, close to Alaska. Its remoteness has been a hindrance in its development, but the depletion of other production fields closer to the consumption and export markets has led to exploratory activities. In recent projections, the Canadian National Energy Board (2009) estimates that production will start in the Mackenzie Delta in 2017 at 0.29 trillion cubic feet and reach 0.44 trillion cubic feet in later years.

The Canadian National Energy Board projections extend through 2020 and show Canada exporting 2.5 trillion cubic feet of natural gas to U.S. markets, including re-exports of 0.5 trillion cubic feet of LNG. In contrast, NEMS-RFF puts net imports of natural gas from Canada at only 1.2 trillion cubic feet in 2020. The differences between these two projections suggest that Canada could provide backup supplies of natural gas should U.S. natural gas production fail to meet expectations. It also suggests the possibility of a North American natural gas market awash in supplies.

### *6.7 Mexican Imports*

In contrast with Canada, the Mexican natural gas market is only weakly linked to the U.S. market, with a small amount of pipeline exports from the United States to Mexico and Baja California used for LNG imports destined for California. Mexico is also a potential competitor with the United States for imported LNG. The projected growth of Mexican natural gas consumption (and how it is met) increases uncertainty about the availability of natural gas resources to the United States.

Until the early 1990s, Mexico was self-sufficient in natural gas. Since 2000, however, Mexico has imported significant quantities of natural gas to meet rapidly rising domestic consumption. Imports have ranged from 15 to 20 percent of consumption since 2004 (BP 2009).

Looking forward, the Mexican Ministry of Energy (Secretaría de Energía 2008) projects that Mexican natural gas consumption will continue growing and domestic production will plateau in 2010 with imports continuing to rise. NEMS-RFF shows slightly lower Mexican imports, but the two projections move together. Nonetheless, the composition of the expected imports differs according to the two sources, with the Mexican Ministry of Energy projecting that all of its imports will be met by LNG by 2015, and NEMS-RFF projecting increasing flows from the United States to Mexico via pipeline.

Over the shorter term, an outcome closer to the Mexican outlook for LNG imports would increase the availability of natural gas in the United States, although that may mean that Mexico is paying higher prices for LNG than it would for natural gas imported from the United States. Over the longer term, Mexico presents the potential for rapidly rising natural gas demand, which could reduce availability and boost prices in U.S. markets.

## 7. Summary and Conclusions

To examine how natural gas supplies affect the implementation of policies to reduce $CO_2$ emissions, we compare five scenarios that address different perspectives on natural gas availability, the availability of other resources, and climate policy. We implemented these scenarios with NEMS-RFF and ran them through 2030. A comparison of the scenarios shows how the relative abundance or scarcity of natural gas supplies might affect the use of natural gas as a bridge fuel to a low-carbon future.

We find that abundant natural gas supplies increase use in most sectors of the economy but do nothing by themselves to create a bridge to a low-carbon future. Without a carbon policy in place, abundant and inexpensive natural gas fosters greater energy consumption and displaces the use of nuclear and renewable resources to generate electric power. Even though coal and oil use fall, the result is higher $CO_2$ emissions.

In contrast, if a market-based policy, such as a cap-and-trade system, is in place to reduce $CO_2$ emissions, abundant supplies of natural gas can make a contribution in the transition to a low-carbon future. With abundant natural gas resources, the estimated price of $CO_2$ emissions in a cap-and-trade system is slightly lower and policy implementation is less costly. Moreover, the share of electric power generation from natural gas is greater in 2030 than in 2010 and much greater than with less abundant natural gas resources.

Other factors and policies could affect the use of natural gas. If the use of nuclear and renewable energy for electric power generation develops more slowly than is expected, abundant natural gas could prove more important as a bridge fuel in low-carbon policies. On the other hand, the use of intervening mandates—such as renewable portfolio standards—in conjunction with a cap-and-trade system can substantially alter market outcomes, reduce the use of natural gas, and increase the costs of reducing $CO_2$ emissions.

From a broader perspective, our analysis finds that the most cost-effective means for reducing $CO_2$ emissions depend greatly on projected resource availability and technology changes—both of which are uncertain. If policymakers are to develop cost-effective policies for controlling $CO_2$ emissions, they must accurately predict the future or develop policies that are robust across different projected futures. Economic theory suggests that pricing schemes—such as cap-and-trade systems or carbon taxes—are robust in finding the most cost-effective means for reducing $CO_2$ emissions, regardless of how technology evolves or how much natural gas or other energy resources are available.

## Tables and Figures

### Table 1. U.S. LNG Import Terminals (May 2009)

| Location | Daily capacity billion cubic feet | Annual capacity trillion cubic feet |
|---|---|---|
| Everett, MA | 1.035 | 0.378 |
| Cove Point, MD | 1.800 | 0.657 |
| Elba Island, GA | 1.200 | 0.438 |
| Lake Charles, LA | 2.100 | 0.767 |
| Gulf of Mexico | 0.500 | 0.183 |
| Offshore Boston | 0.800 | 0.292 |
| Freeport, TX | 1.500 | 0.548 |
| Sabine, LA | 2.600 | 0.949 |
| Total | | 4.210 |

*Source:* Federal Energy Regulatory Commission.

### Table 2. Natural Gas Use in 2030, by Selected Sector

| | Scenario 1 trillion cubic feet | Scenario 2 trillion cubic feet | Difference |
|---|---|---|---|
| Total | 23.46 | 26.04 | 11.0% |
| Electric power generation | 6.71 | 8.23 | 22.5% |
| Industrial natural gas use | 6.29 | 6.89 | 9.5% |
| Commercial natural gas use | 3.43 | 3.63 | 5.8% |
| Residential natural gas use | 4.87 | 5.02 | 3.1% |

*Source:* NEMS-RFF projections.

### Table 3. Natural Gas Use in 2030, by Selected Sector

| | Scenario 1 trillion cubic feet | Scenario 3 trillion cubic feet | Difference |
|---|---|---|---|
| Total | 23.46 | 21.79 | –7.1% |
| Electric power generation | 6.71 | 5.70 | –15.1% |
| Industrial natural gas use | 6.29 | 6.06 | –3.7% |
| Commercial natural gas use | 3.43 | 3.29 | –4.1% |
| Residential natural gas use | 4.87 | 4.68 | –3.9% |

*Source:* NEMS-RFF projections.

**Table 4. Natural Gas Use in 2030, by Selected Sector**

| | Scenario 2 trillion cubic feet | Scenario 4 trillion cubic feet | Difference |
|---|---|---|---|
| Total | 26.04 | 25.32 | –2.8% |
| Electric power generation | 8.23 | 8.47 | 2.9% |
| Industrial natural gas use | 6.89 | 6.47 | –6.2% |
| Commercial natural gas use | 3.63 | 3.39 | –6.5% |
| Residential natural gas use | 5.02 | 4.77 | –5.0% |

*Source:* NEMS-RFF projections.

**Table 5. Electric Power Generation in 2030, by Selected Source**

| | Scenario 1 billion kWh | Scenario 3 billion kWh | Scenario 2 billion kWh | Scenario 4 billion kWh |
|---|---|---|---|---|
| Total | 5,058 | 4,640 | 5,159 | 4,696 |
| Natural gas | 981 | 872 | 1,233 | 1,305 |
| Coal | 2,311 | 1,306 | 2,223 | 1,070 |
| Nuclear | 890 | 1,204 | 849 | 1,183 |
| Renewable sources (incl. hydro) | 795 | 1,186 | 778 | 1,067 |

*Source:* NEMS-RFF projections.

**Table 6. Natural Gas Use in 2030, by Selected Sector**

| | Scenario 1 trillion cubic feet | Scenario 4 trillion cubic feet | Difference |
|---|---|---|---|
| Total | 23.46 | 25.32 | 7.9% |
| Electric power generation | 6.71 | 8.47 | 26.1% |
| Industrial natural gas use | 6.29 | 6.47 | 2.8% |
| Commercial natural gas use | 3.43 | 3.39 | –1.1% |
| Residential natural gas use | 4.87 | 4.77 | –2.1% |

*Source:* NEMS-RFF projections.

**Table 7. Natural Gas Use in 2030, by Selected Sector**

| | Scenario 4 trillion cubic feet | Scenario 5 trillion cubic feet | Difference |
|---|---|---|---|
| Total | 25.32 | 26.53 | 4.8% |
| Electric power generation | 8.47 | 9.79 | 15.7% |
| Industrial natural gas use | 6.47 | 6.36 | –1.8% |
| Commercial natural gas use | 3.39 | 3.36 | –0.8% |
| Residential natural gas use | 4.77 | 4.73 | –0.7% |

*Source:* NEMS-RFF projections.

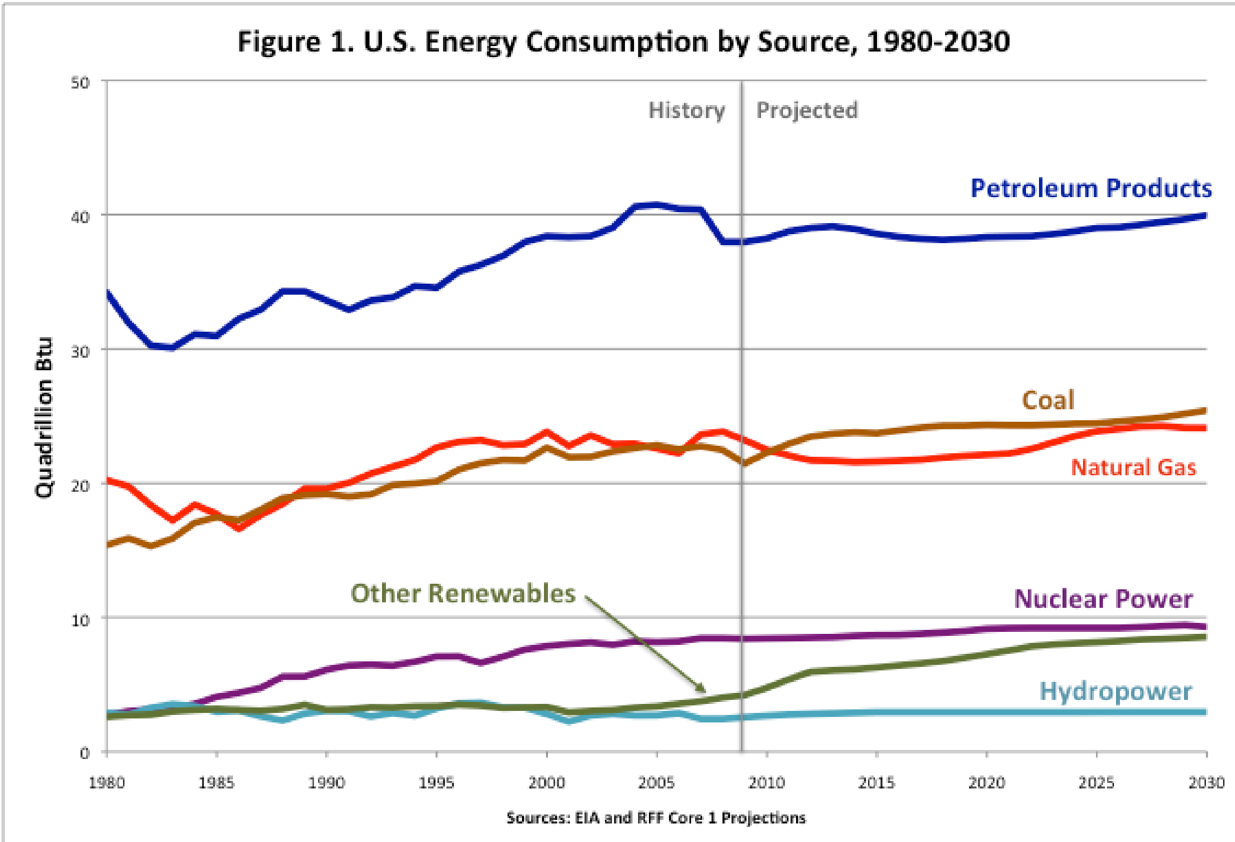


Figure 1. U.S. Energy Consumption by Source, 1980-2030
Quadrillion Btu
History
Projected
Petroleum Products
Coal
Natural Gas
Other Renewables
Nuclear Power
Hydropower
0
10
20
30
40
50
1980
1985
1990
1995
2000
2005
2010
2015
2020
2025
2030
Sources: EIA and RFF Core 1 Projections

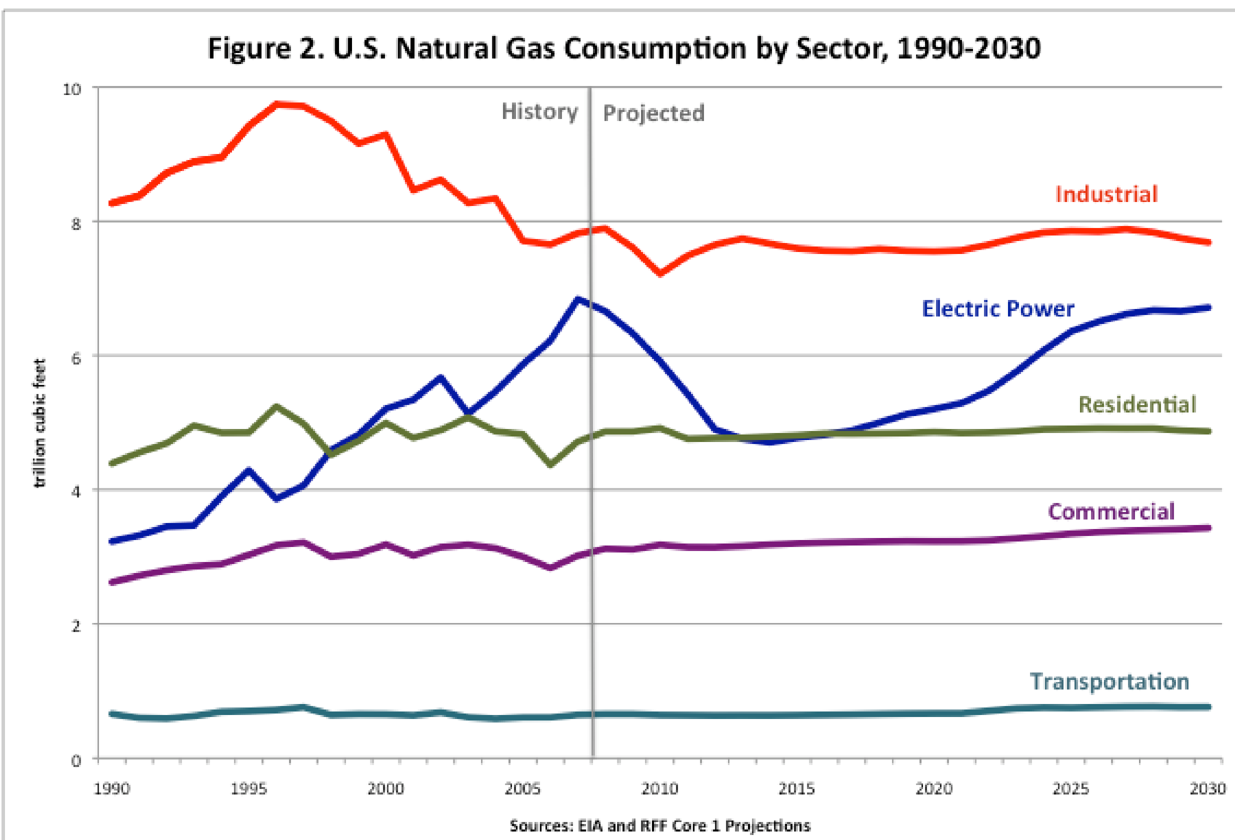


Figure 2. U.S. Natural Gas Consumption by Sector, 1990-2030
trillion cubic feet
History
Projected
Industrial
Electric Power
Residential
Commercial
Transportation
0
2
4
6
8
10
1990
1995
2000
2005
2010
2015
2020
2025
2030
Sources: EIA and RFF Core 1 Projections

**Figure 3. Sources of U.S. Natural Gas, 1990-2030**

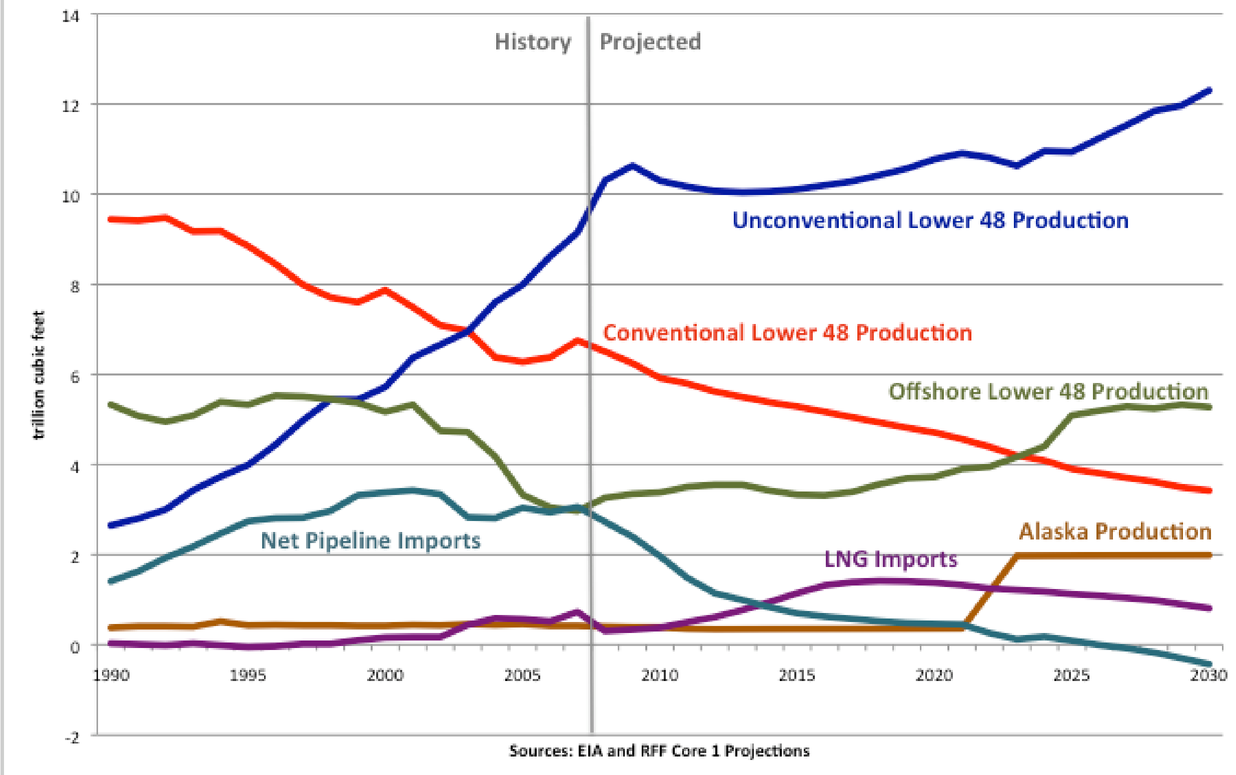



**Figure 4. Shale Gas Resources, Lower 48 States**


Source: Energy Information Administration based on data from various published studies
Updated: May 28, 2009

Figure 5. U.S. Natural Gas Transportation and Distribution

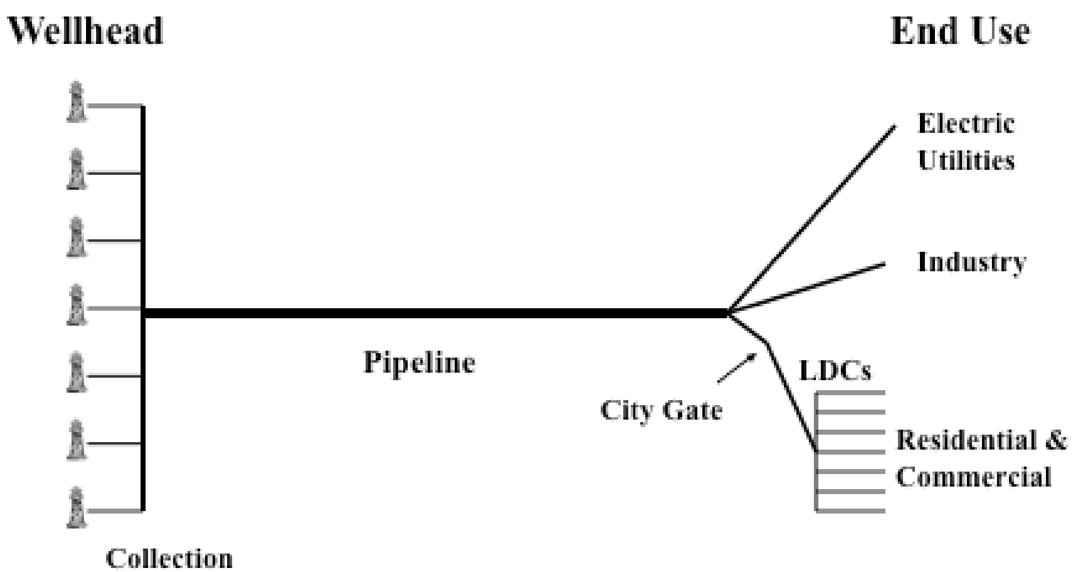



**Figure 6. TransCanada's Proposed Alaska Pipeline**

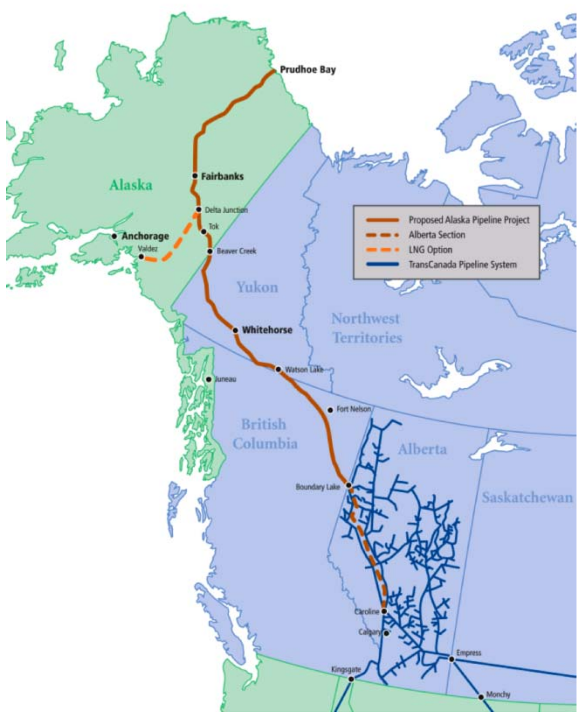
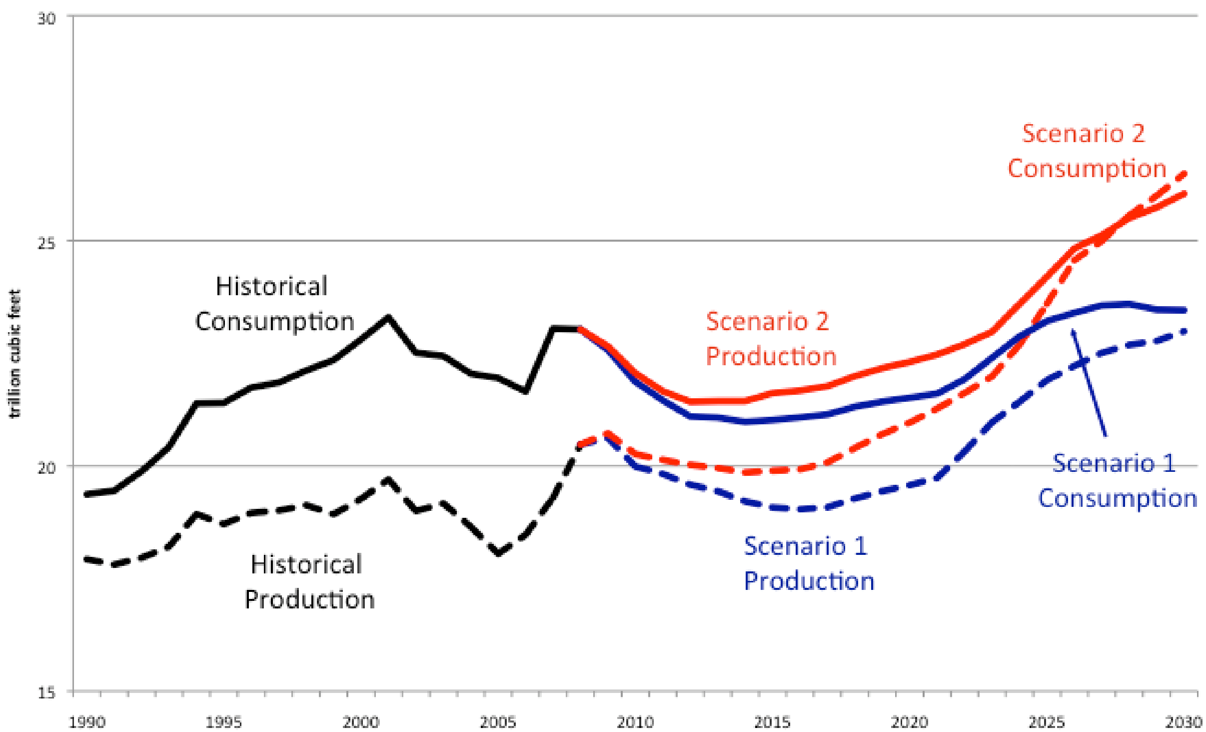


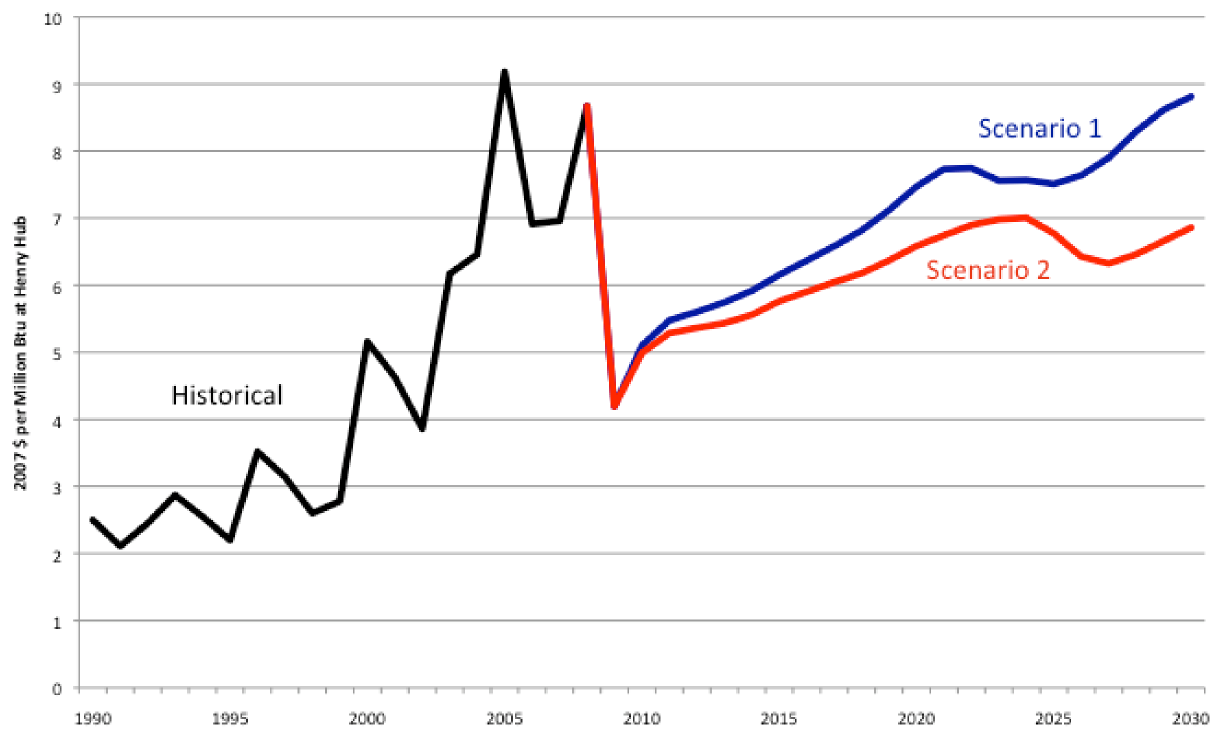
**Figure 7. Mackenzie Delta**


**Figure 8. U.S. Natural Gas Consumption and Production**



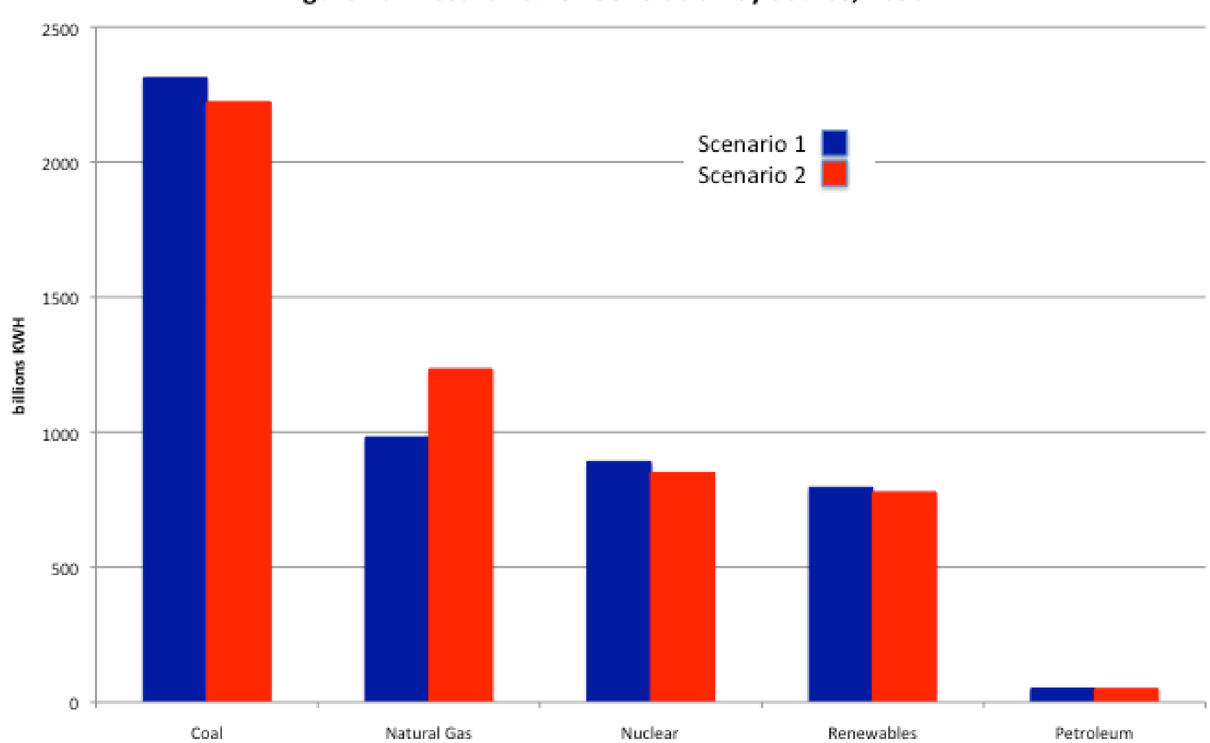

Sources: EIA and NEMS-RFF Projections

Figure 9. U.S. Natural Gas Prices




Sources: EIA and NEMS-RFF Projections

Figure 10. Electric Power Generation by Source, 2030




Source: NEMS-RFF

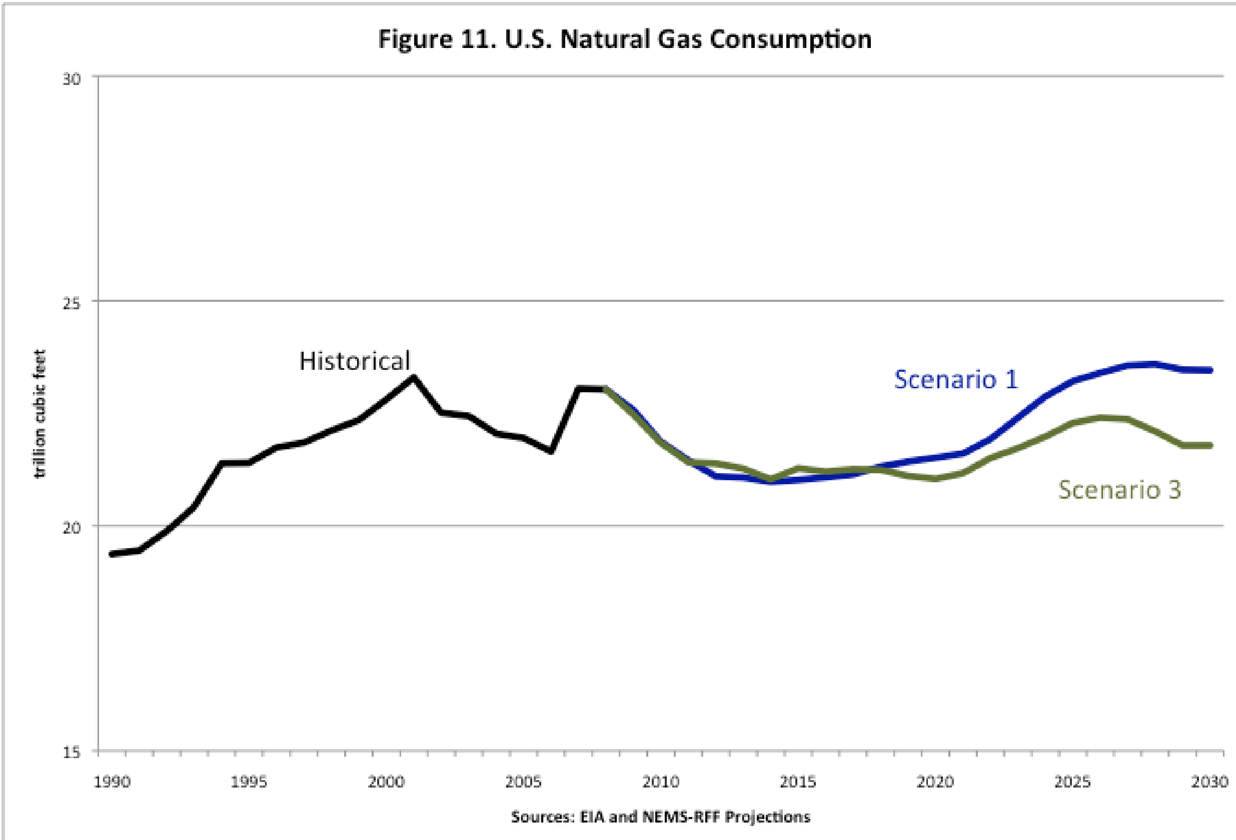


Figure 11. U.S. Natural Gas Consumption
trillion cubic feet
30
25
20
15
Historical
Scenario 1
Scenario 3
1990
1995
2000
2005
2010
2015
2020
2025
2030
Sources: EIA and NEMS-RFF Projections

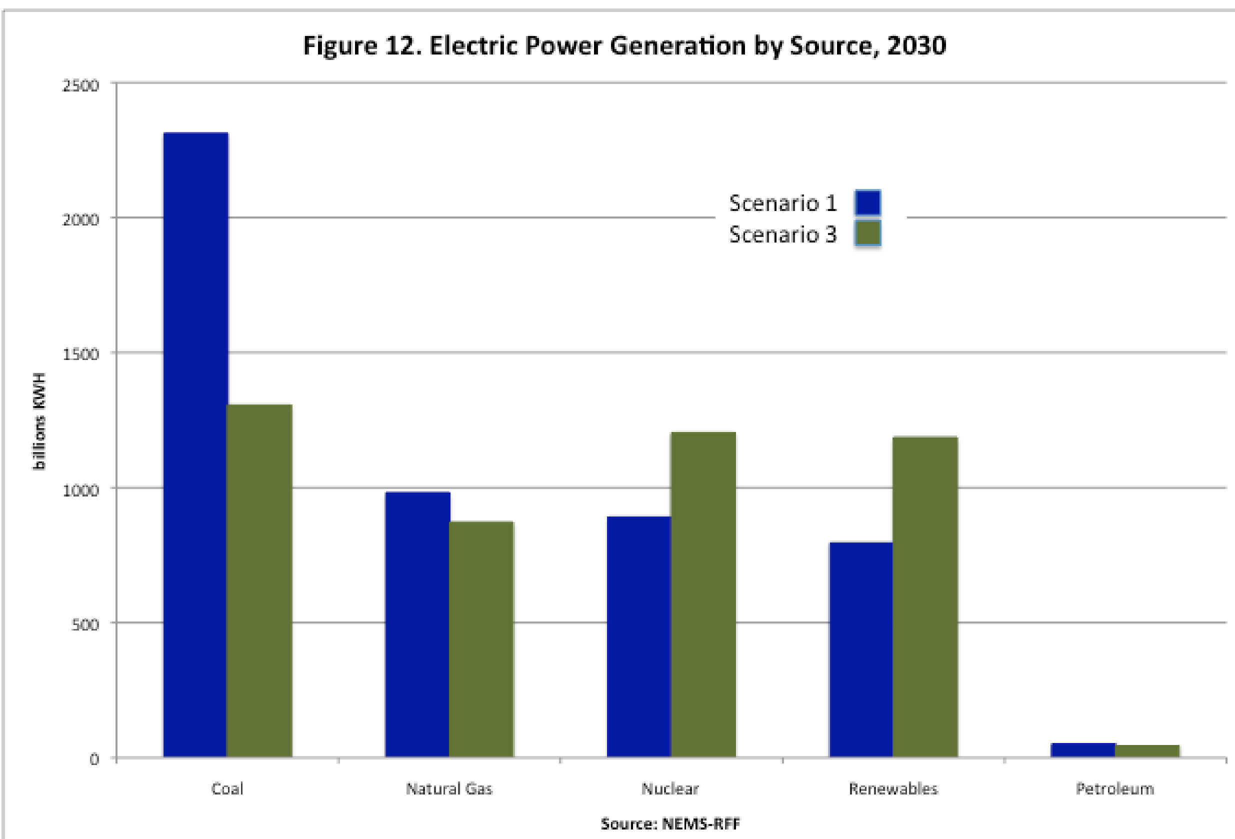


Figure 12. Electric Power Generation by Source, 2030
billions KWH
2500
2000
1500
1000
500
0
Scenario 1
Scenario 3
Coal
Natural Gas
Nuclear
Renewables
Petroleum
Source: NEMS-RFF

**Figure 13. U.S. Natural Gas Consumption**

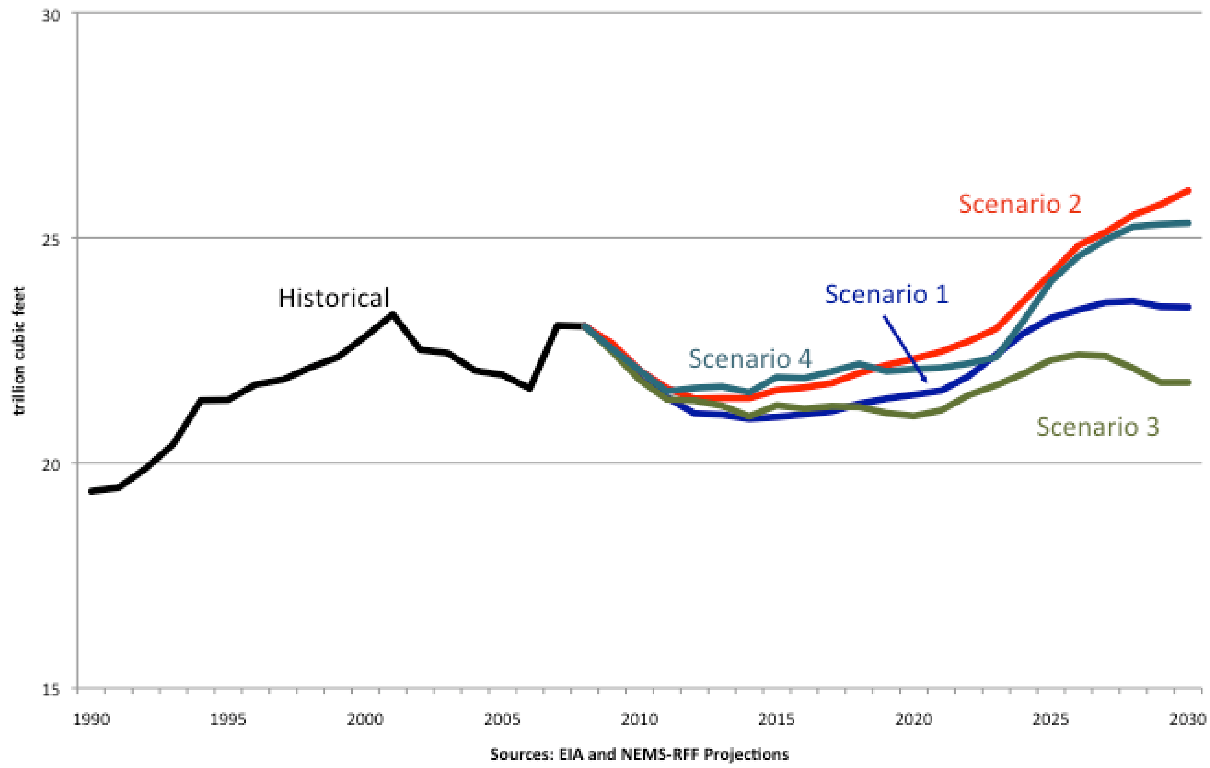



**Figure 14. Electric Power Generation by Source, 2030**

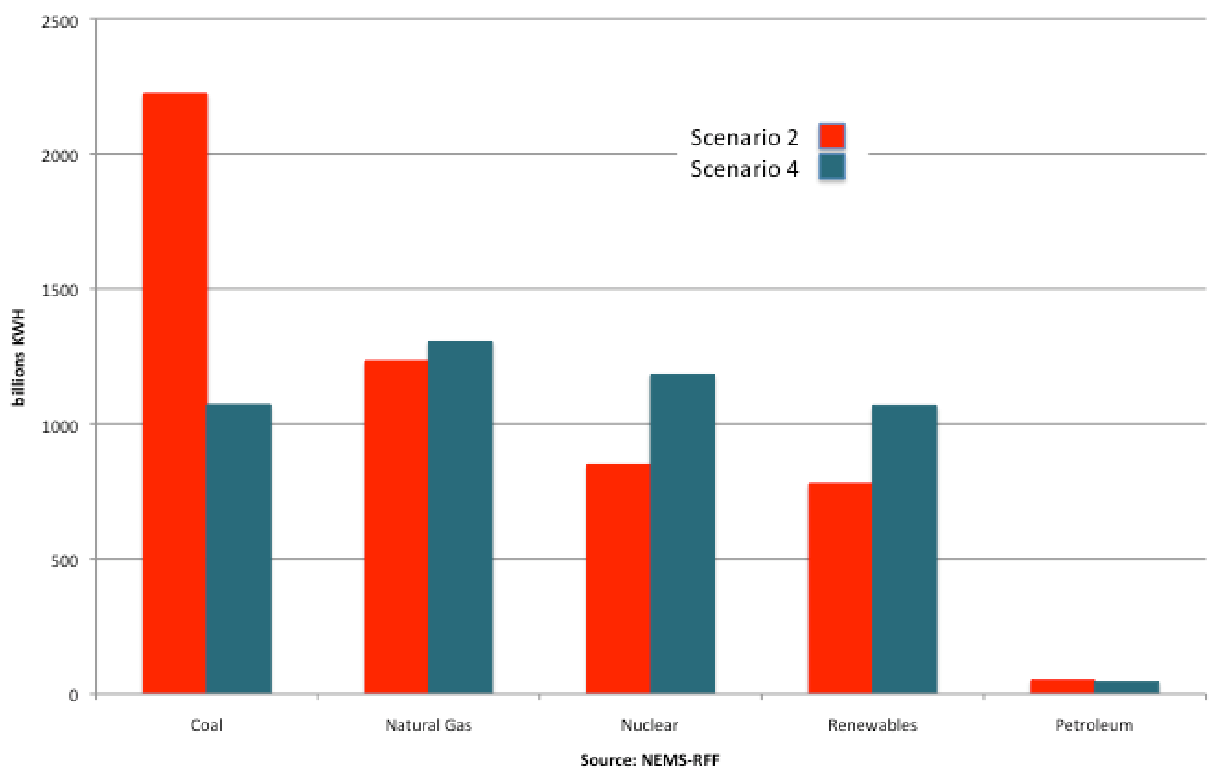
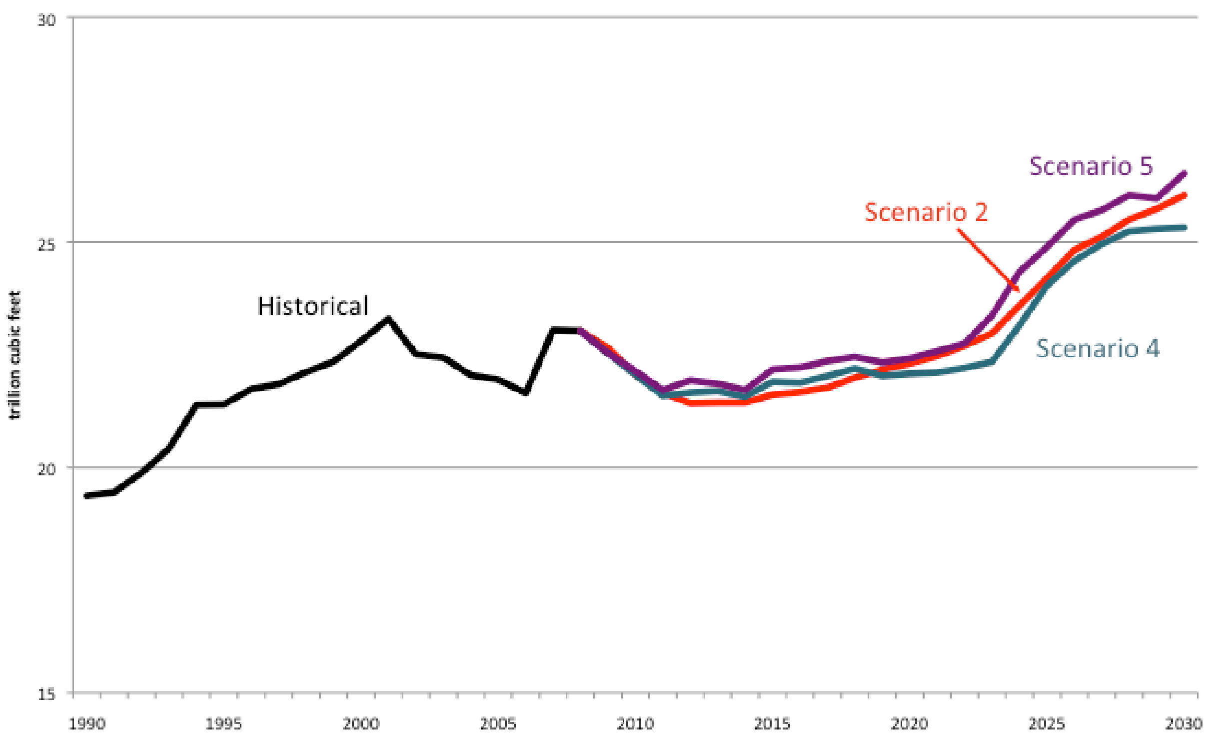
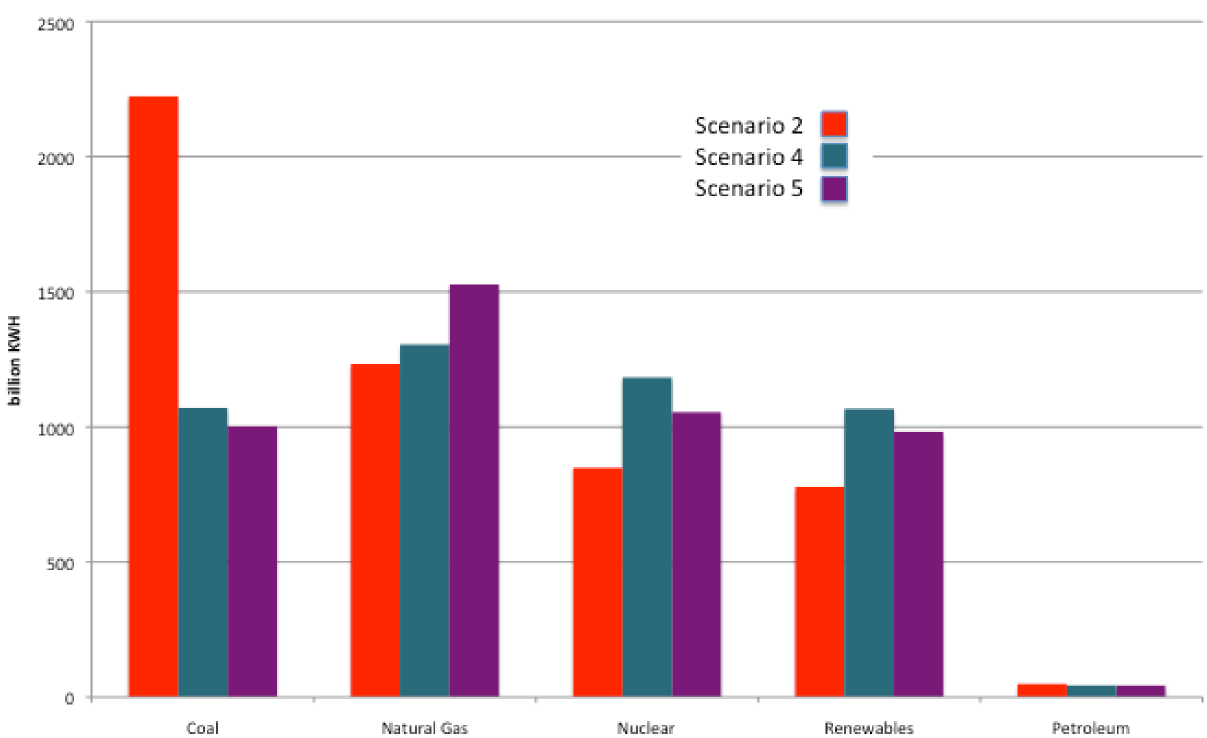


Figure 15. U.S. Natural Gas Consumption




Sources: EIA and NEMS-RFF Projections

Figure 16. Electric Power Generation by Source, 2030




Source: NEMS-RFF Projections

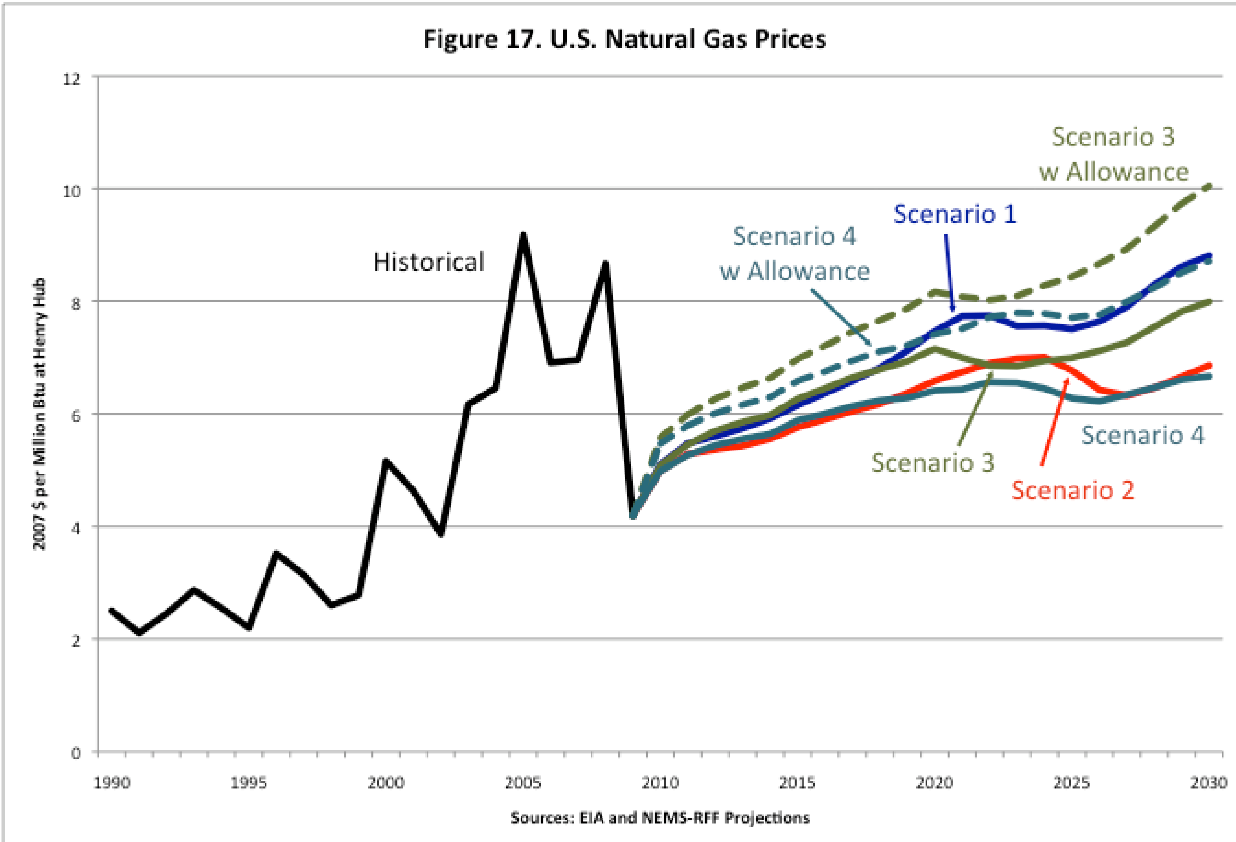


Figure 17. U.S. Natural Gas Prices
2007 $ per Million Btu at Henry Hub
Historical
Scenario 3
w Allowance
Scenario 1
Scenario 4
w Allowance
Scenario 3
Scenario 4
Scenario 2
Sources: EIA and NEMS-RFF Projections

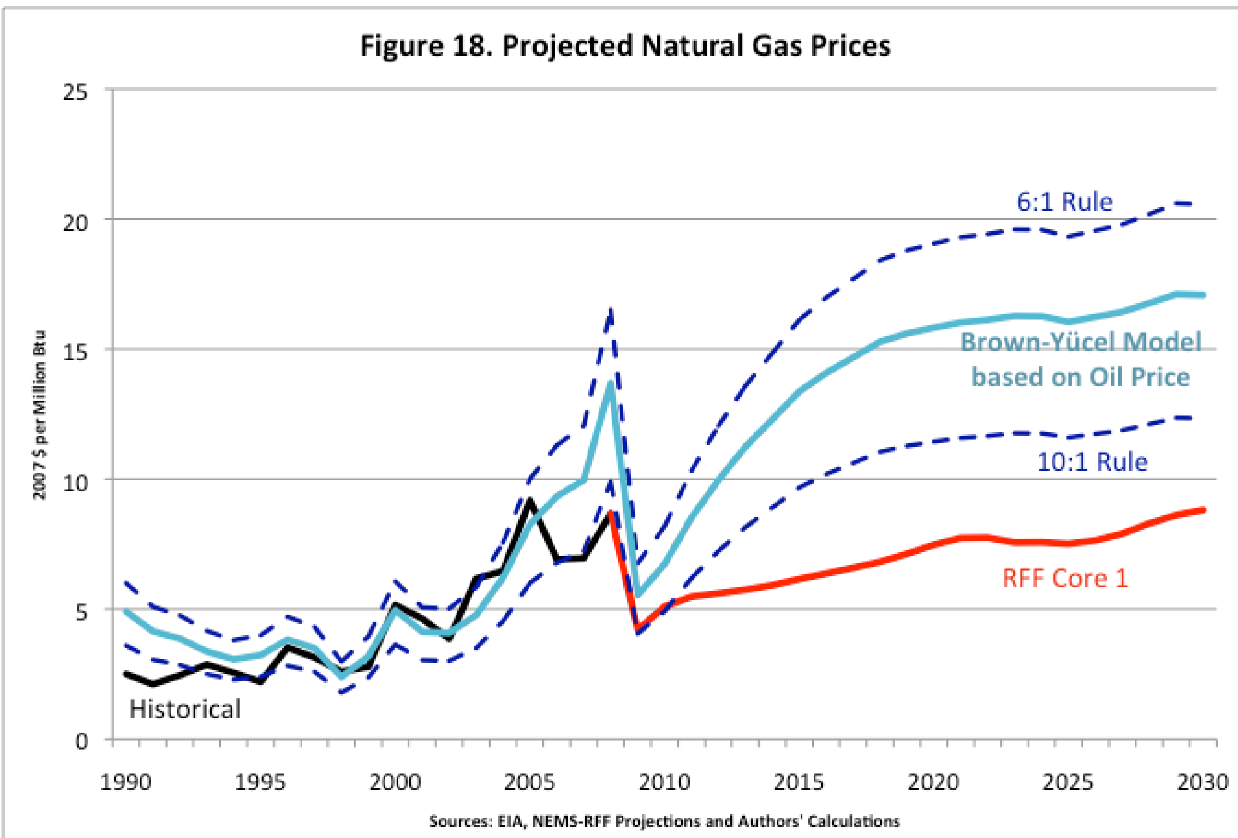


Figure 18. Projected Natural Gas Prices
2007 $ per Million Btu
6:1 Rule
Brown-Yücel Model
based on Oil Price
10:1 Rule
RFF Core 1
Historical
Sources: EIA, NEMS-RFF Projections and Authors' Calculations

## Appendix A. The Five Scenarios

**Scenario 1 (BAU–Low Gas)** represents business as usual with estimates of U.S. shale gas resources at 269.3 trillion cubic feet. This case is based on EIA's *Annual Energy Outlook 2009* as revised in April to include energy provisions in the stimulus package, but it pulls new corporate average fuel economy standards forward from 2020 to 2016. (This case is also known as NEMS-RFF Core 1.)

**Scenario 2 (BAU–High Gas)** represents business as usual with higher estimates of U.S. shale resources. It is based on Scenario 1 with PGC estimates of U.S. shale gas resources at 615.9 trillion cubic feet.

**Scenario 3 ($CO_2$ Policy–Low Gas)** represents the implementation a low-carbon policy with the low estimates of U.S. shale gas resources. It is based on Scenario 1 with a cap-and-trade policy with $CO_2$ emissions targets similar to those in the Waxman–Markey bill and to those proposed by the Obama administration prior to the U.N. climate conference in Copenhagen. (This case is also known as NEMS-RFF Core 2.)

**Scenario 4 ($CO_2$ Policy–High Gas)** represents the implementation of a low-carbon policy with the high estimates of U.S. shale gas resources. It is based on Scenario 3 with the higher estimates of U.S. shale gas resources.

**Scenario 5 ($CO_2$ Policy–High Gas–Limited Alternatives)** represents the implementation of a low-carbon policy with high estimates of U.S. shale gas resources and limits on the use of nuclear power, carbon capture and sequestration (CCS), and renewable power generation. These limits restrict the use of nuclear power to no more than 130 gigawatts by 2030, the use of CCS to 2 gigawatts, and renewable power generation to no more than is found under Scenario 4. Scenario 5 is based on Scenario 4 with the restrictions described.

## Appendix B. A Comparison of Natural Gas Market Models

Six models of natural gas markets play a prominent role in the academic literature and/or are used by industry. These models include the Rice World Gas Trade Model (RWGTM), World Gas Model (WGM), GASTALE, ICF's Gas Market Model (ICF GMM), GASMOD, and GRIDNET. In what follows, we briefly examine the main characteristics of these models, including represented market players, geographical coverage, and regional and periodical density. These comparisons reveal that NEMS-RFF provides the most detailed representation for North American natural gas markets, the most interaction with other fuels, and/or the appropriate time scale for analysis.

**Table B-1. Summary of Natural Gas Model Characteristics**

| Model | Type | Region(s) | Market power | Number of nodes | Time Scale | Density | Seasons | Sectors | Capacity expansions |
|---|---|---|---|---|---|---|---|---|---|
| NEMS-RFF | LP | USA+Canada | No | 15[a] | 2030 | Yearly | 2 | 5[b] | Endogenous |
| WGM | MCP | World | Yes | 41 | 2030 | 5years | 2 | 3 | Endogenous |
| RWGTM | CGE | World | No | 460 | 2050 | 5years | 1 | 1 | Endogenous |
| GASMOD[c] | MCP | Europe+LNG | Yes | 6 | 2025 | 10years | 1 | 1 | Endogenous |
| GASTALE | MCP | Europe+LNG | Yes | 19 | 2030 | 5years | 3 | 3 | Endogenous |
| GRIDNET | LP | USA | No | 18,000 | Operational | Monthly | 12 | N/A | Exogenous |
| ICF GMM | LP? | USA | No | 114 | Several years | Monthly | 12 | 4 | Exogenous |

*Notes:* CGE, Computable General Equilibrium; LP, Linear Program; MCP, Mixed Complementarity Problem.

[a] United States 12, Canada 2, and Mexico 1.

[b] Includes electric power generation, which is not considered an end-use sector in NEMS.

[c] The dynamic version of GASMOD.

RWGTM and WGM provide much less detail than NEMS-RFF for the North American market (Table B-1). The principal advantage of these models is global coverage, which allows the models to better capture the interaction between natural gas markets in different world regions. WGM also addresses the potential for the development of international market power, but it does not allow for the development of supply and demand conditions in a detailed bottom-up approach that takes into account changing economic conditions.

GASMOD and GASTALE also address market power aspects explicitly, but their coverage is strictly European when it comes to demand. Gridnet and ICF GMM offer U.S.

coverage but are designed to support short- to medium-term business decisions. Neither is well suited for long-term scenario analysis.

In comparison with some other models, the two principal issues that NEMS-RFF does not address well are the interaction of the North American natural gas market with the rest of the world and the market power aspects that may arise in global natural gas supply. Because current projections show the North American market as nearly self sufficient, these issues are probably not too important. To the extent that any scenarios examined show sizable imports of LNG, these issues may deserve more attention.

### *Rice World Gas Trade Model*

According to Hartley et al. (2004a and 2004b), Hartley and Medlock (2005), and Brotzen (2007), the Rice World Gas Trade Model (RWGTM) is a model of international natural gas markets developed at Rice University with Market Builder software from Altos Management Partners. RWGTM is a dynamic spatial equilibrium model. Periods are linked through the optimal scheduling of production over time. The demand side is modeled via a bottom-up approach, using econometric estimates based on GDP and population size as well as prices of gas and competitive fuels. Agents at the supply side of the model maximize their discounted profits, based on expected prices and demand levels.

The model includes the exploration of new reserves and the construction and expansion of transportation options and determines market-clearing prices to balance demands and supply. In a perfectly competitive setting, producers maximize their discounted profits. The model develops and expands pipeline and LNG transportation infrastructure.

RWGTM takes a hub-and-spoke approach to LNG transportation. Market power aspects are not explicitly accounted for. The time horizon of the model is 2050, and the model data set includes more than280 demand regions and 180 supply regions.

### *World Gas Model*

According to Gabriel and Egging (2009) and Egging et al. (2009), the World Gas Model (WGM) is a multiperiod, mixed-complementarity model for the global natural gas market, allowing for endogenous capacity expansions in the LNG, pipeline, and storage sectors. The model contains 41 countries and regions and covers about 98 percent of worldwide gas consumption and production, both with seasonal variation. The model includes a detailed representation of border-crossing natural gas pipelines and contractual and spot trades in LNG.

The represented market agents include producers and traders as competitive players; liquefaction, regasification, pipelines, and storage as regulated players; and three final consumption sectors—power generation, industry, and residential/commercial. Traders, in the pipeline as well as in the LNG market, can exert market power relative to the end-user markets. The model base year is 2005 and covers the period up to 2040 in five-year steps. Future production capacities and consumption curves are scenario-dependent input parameters, whereas capacity expansions in transportation and storage are endogenously determined by model agents. The model is equipped to represent a global cartel in the world natural gas market.

### *GASMOD*

According to Holz et al. (2008) and Holz (2009) GASMOD is a two-stage gaming model for the European upstream and downstream gas markets developed by DIW Berlin. The first stage is a noncooperative game wherein producers determine their production and export levels to European countries. In the second stage, traders determine their deliveries to consumer markets within Europe. Pipeline and LNG import capacities limit the transportation of gas to and within the continent. The geographical coverage of the model is Europe and exporters to Europe. Two model versions are available. The static model allows for market power on two levels (double marginalization): producers/exporters to traders and traders to end users. It contains 13 exporting countries and 17 importing regions. The dynamic model contains the three largest exporters to Europe and the three largest importers in Europe. The dynamic model assumes a perfectly competitive upstream market and includes endogenous capacity expansions. The distinguished market players are producers, traders, consumers, pipelines, and LNG regasification. The period up to 2025 is represented in three 10-year periods. No seasons or sectors are distinguished.

### *GASTALE*

According to Lise and Hobbs (2009), GASTALE is a gas market model for the European gas market developed by the Energy Research Center of the Netherlands. GASTALE is a mixed-complementarity model with endogenous investments by transmission and storage system operators. The model solves for a single-year short-run equilibrium in each five-year period for a number of consecutive periods. In between each period solution, a separate routine decides on capacity expansion levels for pipelines, liquefaction, regasification, and storage, based on the expected congestion prices (generated with an open-loop information structure). Investments should bring the expected capacity congestion prices below an acceptable threshold. The represented market agents include producers, consumers, and transmission and storage operators. Producers can exercise market power relative to end-user markets. Transmission and storage are assumed to be regulated players. Production capacity expansions and development of the demand curves are exogenous to the model. The model has three seasons and three final consumption sectors: power generation, industry, and residential/commercial.

The regions represented in the model include Europe, the gas-exporting neighboring regions, and some representative LNG exporters. Of the 19 regions, 7 serve only as consumers, 9 only as producers, and 3 as both producers and consumers. The model is solved in five-year intervals through 2030.

### *GRIDNET*

According to Brooks and Neill (2010), Gridnet models a large network for the United States. It contains more than 18,000 nodes and 200,000 pipelines. The model is very similar to a huge, generalized, minimum-cost flow problem with losses and some complicating constraints. It is a decision support tool that simultaneously addresses supply, demand, and the transportation of natural gas for gas trading companies. The detail in the representation of the pipeline network supports the operational planning problem of companies, such as the routing of existing contract volumes, as well as analyzing opportunities and setting prices for new contracts.

The model has two modes: an operational mode and a planning mode. Many contractual, capacity, and other constraints add operational restrictions; therefore, the size of the operational model is an order of magnitude smaller than the whole model, and it can be solved in little time. This is further facilitated by the pre-computation of costs and losses for origin–destination node pairs. As long as the pipeline system does not have bottlenecks, the pre-computed values remain valid. When used for planning, several of the constraints are relieved, in particular the joint constraints for minimum and maximum aggregate deliveries at sets of destinations. This allows for a more global optimization approach at the cost of much higher calculation times, using special solvers rather than general LP.

Market power is not addressed in Gridnet. The (implicitly) distinguished market players are producers, consumers, and pipelines. The model is not a market equilibrium model, and sectors and seasons are not represented as such. However, the time resolution of the model and the supply contracts that companies have to meet (existing) or those they are investigating (opportunities) imply a high level of detail.

### *ICF's GMM*

According to ICF International (2009 and 2010), ICF GMM determines monthly market-clearing prices for supply and demand in the United States and Canada. The model investigates the impact of different assumptions, such as those regarding supply sources and demand drivers on prices, produced volumes, and transportation flows.

The model contains 114 nodes, of which 77 are supply nodes. Most U.S. states are represented as single nodes; however, larger states are represented as several nodes. Other nodes represent the Canadian provinces, offshore pipeline landing points, border crossings with Canada and Mexico, the Alaskan LNG export terminal, and all LNG import terminals. The represented market players are producers, consumers, pipelines, and LNG terminals. Market power is not addressed.

Supply curves, which represent production from existing and new fields, imports from Mexico, and LNG regasification, address costs for storage and pipeline use. An optional add-on is a hydrocarbon supply model that provides more detail for gas production. GMM includes four demand sectors: power, industry, residential, and commercial. A separate electricity market module projects natural gas consumption for power generation. The demand curves for other sectors are driven by weather (degree days) and economic output. LNG exports and exports to Mexico are also represented on the demand side of the model. Transportation capacities are exogenous to the model.

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