# The Future of Natural Gas

AN INTERDISCIPLINARY MIT STUDY

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MIT Energy Initiative



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While the members of the advisory committee provided invaluable perspective and advice to the study group, individual members may have different views on one or more matters addressed in the report. They are not asked to individually or collectively endorse the report findings and recommendations.

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Supplementary Papers



To view supplementary papers, go to
http://web.mit.edu/mitei/research/studies/natural-gas-2011.shtml

# Foreword and Acknowledgements

The Future of Natural Gas is the fourth in a series of MIT multidisciplinary reports examining the role of various energy sources that may be important for meeting future demand under carbon dioxide ($CO_2$) emissions constraints. In each case, we explore the steps needed to enable competitiveness in a future marketplace conditioned by a $CO_2$ emissions price or by a set of regulatory initiatives. This report follows an interim report issued in June 2010.

The first three reports dealt with nuclear power (2003), coal (2007) and the nuclear fuel cycle (2010 and 2011). A study of natural gas is more complex than these previous reports because gas is a major fuel for multiple end uses — electricity, industry, heating — and is increasingly discussed as a potential pathway to reduced oil dependence for transportation. In addition, the realization over the last few years that the producible unconventional gas resource in the U.S. is very large has intensified the discussion about natural gas as a "bridge" to a low-carbon future. Recent indications of a similarly large global gas shale resource may also transform the geopolitical landscape for gas. We have carried out the integrated analysis reported here as a contribution to the energy, security and climate debate.

Our primary audience is U.S. government, industry and academic leaders, and decision makers. However, the study is carried out with an international perspective.

This study is better as a result of comments and suggestions from our distinguished external Advisory Committee, each of whom brought important perspective and experience to our discussions. We are grateful for the time they invested in advising us. However, the study is the responsibility of the MIT study group and the advisory committee members do not necessarily endorse all of its findings and recommendations, either individually or collectively.

Finally, we are very appreciative of the support from several sources. First and foremost, we thank the American Clean Skies Foundation. Discussions with the Foundation led to the conclusion that an integrative study on the future of natural gas in a carbon-constrained world could contribute to the energy debate in an important way, and the Foundation stepped forward as the major sponsor. MIT Energy Initiative (MITEI) members Hess Corporation and Agencia Naçional de Hidrocarburos (Colombia), the Gas Technology Institute (GTI), Exelon, and an anonymous donor provided additional support. The Energy Futures Coalition supported dissemination of the study results, and MITEI employed internal funds and fellowship sponsorship to support the study as well. As with the advisory committee, the sponsors are not responsible for and do not necessarily endorse the findings and recommendations. That responsibility lies solely with the MIT study group.

We thank Victoria Preston and Rebecca Marshall-Howarth for editorial support and Samantha Farrell for administrative support.

# Abstract

Natural gas is finding its place at the heart of the energy discussion. The recent emergence of substantial new supplies of natural gas in the U.S., primarily as a result of the remarkable speed and scale of shale gas development, has heightened awareness of natural gas as a key component of indigenous energy supply and has lowered prices well below recent expectations. This study seeks to inform discussion about the future of natural gas, particularly in a carbon-constrained economy.

There are abundant supplies of natural gas in the world, and many of these supplies can be developed and produced at relatively low cost. In North America, shale gas development over the past decade has substantially increased assessments of resources producible at modest cost. Consequently, the role of natural gas is likely to continue to expand, and its relative importance is likely to increase even further when greenhouse gas emissions are constrained. In a carbon-constrained world, a level playing field — a carbon dioxide ($CO_2$) emissions price for all fuels without subsidies or other preferential policy treatment —maximizes the value to society of the large U.S. natural gas resource.

There are also a number of key uncertainties: the extent and nature of greenhouse gas emission mitigation measures that will be adopted; the mix of energy sources as the relative costs of fuels and technologies shift over time; the evolution of international natural gas markets. We explore how these uncertainties lead to different outcomes and also quantify uncertainty for natural gas supply and for the U.S. electricity fuel mix.

The environmental impacts of shale development are challenging but manageable. Research and regulation, both state and Federal, are needed to minimize the environmental consequences.

The U.S. natural gas supply situation has enhanced the substitution possibilities for natural gas in the electricity, industry, buildings, and transportation sectors.

In the U.S. electricity supply sector, the cost benchmark for reducing carbon dioxide emissions lies with substitution of natural gas for coal, especially older, less efficient units. Substitution through increased utilization of existing combined cycle natural gas power plants provides a relatively low-cost, short-term opportunity to reduce U.S. power sector $CO_2$ emissions by up to 20%, while also reducing emissions of criteria pollutants and mercury.

Furthermore, additional gas-fired capacity will be needed as backup if variable and intermittent renewables, especially wind, are introduced on a large scale. Policy and regulatory steps are needed to facilitate adequate capacity investment for system reliability and efficiency. These increasingly important roles for natural gas in the electricity sector call for a detailed analysis of the interdependencies of the natural gas and power generation infrastructures.

The primary use of natural gas in the U.S. manufacturing sector is as fuel for boilers and process heating, and replacement with new higher efficiency models would cost-effectively reduce natural gas use. Natural gas could also substitute for coal in boilers and process heaters and provide a cost-effective alternative for compliance with Environmental Protection Agency (EPA) Maximum Achievable Control Technology standards.

In the residential and commercial buildings sector, transformation of the current approach to efficiency standards to one based on full fuel cycle analysis will enable better comparison of different energy supply options (especially

natural gas and electricity). Efficiency metrics should be tailored to regional variations in climate and electricity supply mix.

Within the U.S. market, the price of oil (which is set globally) compared to the price of natural gas (which is set regionally) is very important in determining market share when there is the opportunity for substitution. Over the last decade or so, when oil prices have been high, the ratio of the oil price to the natural gas price has been consistently higher than any of the standard rules of thumb. If this trend is robust, use of natural gas in transportation, either through direct use or following conversion to a liquid fuel, could in time increase appreciably.

The evolution of global gas markets is unclear. A global "liquid" natural gas market is beneficial to U.S. and global economic interests and, at the same time, advances security interests through diversity of supply and resilience to disruption. The U.S. should pursue policies that encourage the development of such a market, integrate energy issues fully into the conduct of U.S. foreign policy, and promote sharing of know-how for strategic global expansion of unconventional gas production.

Past research, development, demonstration, and deployment (RDD&D) programs supported with public funding have led to significant advances for natural gas supply and use. Public-private partnerships supporting a broad natural gas research, development, and demonstration (RD&D) portfolio should be pursued.

# Chapter 1: Overview and Conclusions

## PURPOSE AND OUTLINE OF THE STUDY

Despite its vital importance to the national economy, natural gas has often been overlooked, or at best taken for granted, in the debate about the future of energy in the U.S. Over the past two or three years this has started to change, and natural gas is finding its place at the heart of the energy discussion.

There are a number of reasons for this shift. The recent emergence of substantial new supplies of natural gas in the U.S., primarily as a result of the remarkable speed and scale of shale gas development, has heightened awareness of natural gas as a key component of indigenous energy supply and lowered prices well below recent expectations. Instead of the anticipated growth of natural gas imports, the scale of domestic production has led producers to seek new markets for natural gas, such as an expanded role in transportation. Most importantly for this study, there has been a growing recognition that the low carbon content of natural gas relative to other fossil fuels could allow it to play a significant role in reducing carbon dioxide ($CO_2$) emissions, acting as a "bridge" to a low-carbon future.

Within this context, the MIT study of *The Future of Natural Gas* seeks to inform the discussion around natural gas by addressing a fundamental question: *what is the role of natural gas in a carbon-constrained economy?*

In exploring this question, we seek to improve general understanding of natural gas, and examine a number of specific issues. How much natural gas is there in the world, how expensive is it to develop, and at what rate can it be produced? We start from a global perspective, and then look in detail at U.S. natural gas resources, paying particular attention to the extent and cost of shale gas resources, and whether these supplies can be developed and produced in an environmentally sound manner.

Having explored supply volumes and costs, we use integrated models to examine the role that natural gas could play in the energy system under different carbon-constraining mechanisms or policies. It is important to recognize that *the study does not set out to make predictions or forecasts of the likelihood or direction of $CO_2$ policy in the U.S.* Rather, we examine a number of different scenarios and explore their possible impacts on the future of natural gas supply and demand.

Natural gas is important in many sectors of the economy — for electricity generation, as an industrial heat source and chemical feedstock, and for water and space heating in residential and commercial buildings. Natural gas competes directly with other energy inputs in these sectors. But it is in the electric power sector — where natural gas competes with coal, nuclear, hydro, wind, and solar — that inter-fuel competition is most intense. We have, therefore, explored in depth how natural gas performs in the electric power sector under different scenarios. We have also taken a close look at the critical interaction between intermittent forms of renewable energy, such as wind and solar, and gas-fired power as a reliable source of backup capacity.

We look at the drivers of natural gas use in the industrial, commercial, and residential sectors, and examine the important question of whether natural gas, in one form or another, could be a viable and efficient substitute for gasoline or diesel in the transportation sector. We also examine the possible futures of global natural gas markets, and the geopolitical significance of the ever-expanding role of natural gas in the global economy. Finally, we make recommendations for research and development priorities and for the means by which public support should be provided.

## HIGH-LEVEL FINDINGS

The findings and recommendations of the study are discussed later in this chapter, and covered in detail in the body of this report. Nevertheless, it is worth summarizing here the highest level conclusions of our study:

1. *There are abundant supplies of natural gas in the world*, and many of these supplies can be developed and produced at relatively low cost. In the U.S., despite their relative maturity, natural gas resources continue to grow, and the development of low-cost and abundant unconventional natural gas resources, particularly shale gas, has a material impact on future availability and price.

2. Unlike other fossil fuels, natural gas plays a major role in most sectors of the modern economy — power generation, industrial, commercial, and residential. It is clean and flexible. *The role of natural gas in the world is likely to continue to expand under almost all circumstances*, as a result of its availability, its utility, and its comparatively low cost.

3. In a carbon-constrained economy, the relative importance of natural gas is likely to increase even further, as it is one of the most cost-effective means by which to maintain energy supplies while reducing $CO_2$ emissions. This is particularly true in the electric power sector, where, in the U.S., *natural gas sets the cost benchmark against which other clean power sources must compete to remove the marginal ton of* $CO_2$.

4. In the U.S., a combination of demand reduction and displacement of coal-fired power by gas-fired generation is the lowest-cost way to reduce $CO_2$ emissions by up to 50%. For more stringent $CO_2$ emissions reductions, further de-carbonization of the energy sector will be required; but *natural gas provides a cost-effective bridge to such a low-carbon future*.

5. Increased utilization of existing natural gas combined cycle (NGCC) power plants provides a relatively, low-cost short-term opportunity to reduce U.S. $CO_2$ emissions by up to 20% in the electric power sector, or 8% overall, with minimal additional capital investment in generation and no new technology requirements.

6. Natural gas-fired power *capacity* will play an increasingly important role in providing backup to growing supplies of intermittent renewable energy, in the absence of a breakthrough that provides affordable utility-scale storage. But in most cases, increases in renewable power generation will be at the expense of natural gas-fired power *generation* in the U.S.

7. The current supply outlook for natural gas will contribute to greater competitiveness of U.S. manufacturing, while the use of more efficient technologies could offset increases in demand and provide cost-effective compliance with emerging environmental requirements.

8. Transformation of the current approach to appliance standards to one based on full fuel cycle analysis will enable better comparison of different energy supply options in commercial and residential applications.

9. Natural gas use in the transportation sector is likely to increase, with the primary benefit being reduced oil dependence. Compressed natural gas (CNG) will play a role, particularly for high-mileage fleets, but the advantages of liquid fuel in transportation suggest that *the chemical conversion of gas into some form of liquid fuel may be the best pathway to significant market penetration*.

10. International gas trade continues to grow in scope and scale, but its economic, security and political significance is not yet adequately recognized as an important focus for U.S. energy concerns.

11. Past research, development, demonstration, and deployment (RDD&D) programs supported with public funding have led to significant advances for natural gas supply and use.

## BACKGROUND

### The Fundamental Characteristics of Natural Gas

Fossil fuels occur in each of the three fundamental states of matter: in solid form as coal; in liquid form as oil; and in gaseous form as natural gas. These differing physical characteristics for each fuel type play a crucial part in shaping each link in their respective supply chains: from initial resource development and production through transportation, conversion to final products, and sale to customers. Their physical form fundamentally shapes the markets for each type of fossil fuel.

Natural gas possesses remarkable qualities. Among the fossil fuels, it has the lowest carbon intensity, emitting less $CO_2$ per unit of energy generated than other fossil fuels. It burns cleanly and efficiently, with very few non-carbon emissions. Unlike oil, natural gas generally requires limited processing to prepare it for end use. These favorable characteristics have enabled natural gas to penetrate many markets, including domestic and commercial heating, multiple industrial processes, and electrical power.

Natural gas also has favorable characteristics with respect to its development and production. The high compressibility and low viscosity of natural gas allows high recoveries from conventional reservoirs at relatively low cost, and also enables natural gas to be economically recovered from even the most unfavorable subsurface environments, as recent developments in shale formations have demonstrated.

These physical characteristics underpin the current expansion of the unconventional resource base in North America, and the potential for natural gas to displace more carbon-intensive fossil fuels in a carbon-constrained world.

On the other hand, because of its gaseous form and low energy density, natural gas is uniquely disadvantaged in terms of transportation and storage. As a liquid, oil can be readily transported over any distance by a variety of means, and oil transportation costs are generally a small fraction of the overall cost of developing oil fields and delivering oil products to market. This has facilitated the development of a truly global market in oil over the past 40 years or more.

By contrast, the vast majority of natural gas supplies are delivered to market by pipeline, and delivery costs typically represent a relatively large fraction of the total cost in the supply chain. These characteristics have contributed to the evolution of regional markets rather than a truly global market in natural gas. Outside North America, this somewhat inflexible pipeline infrastructure gives strong political and economic power to those countries that control the pipelines. To some degree, the evolution of the spot market in Liquefied Natural Gas (LNG) is beginning to introduce more flexibility into global gas markets and stimulate real global trade. The way this trade may evolve over time is a critical uncertainty that is explored in this report.

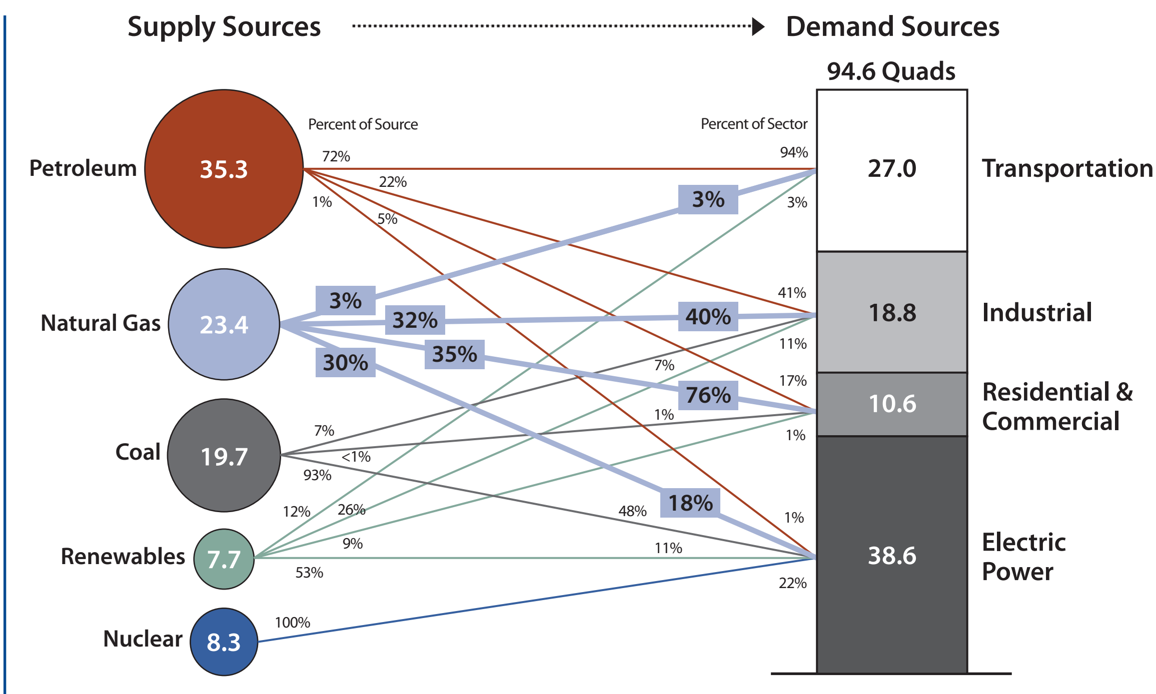
## The Importance of Natural Gas in the Energy System

Natural gas represents a very important, and growing, part of the global energy system. Over the past half century, natural gas has gained market share on an almost continuous basis, growing from some 15.6% of global energy consumption in 1965 to around 24% today. In absolute terms, global natural gas consumption over this period has grown from around 23 trillion cubic feet (Tcf) in 1965 to 104 Tcf in 2009, a more than fourfold increase.

Within the U.S. economy, natural gas plays a vital role. Figure 1.1 displays the sources and uses of natural gas in the U.S. in 2009, and it reveals a number of interesting features that are explored in more detail in the body of this report. At 23.4 quadrillion British thermal units (Btu)[1], or approximately 23 Tcf, gas represents a little under a quarter of the total energy supply in the U.S., with almost all of this supply now coming from indigenous resources. Perhaps of more significance, is the very important role that natural gas plays in all sectors of the economy, with the exception of transport. Very approximately, the use of natural gas is divided evenly between three major sectors: Industrial, Residential and Commercial, and Electric Power. The 3% share that goes to transport is almost all associated with natural gas use for powering oil and gas pipeline systems, with only a tiny fraction going into vehicle transport.

In the Residential and Commercial sectors, natural gas provides more than three-quarters of the total primary energy, largely as a result of its efficiency, cleanliness, and convenience for uses such as space and hot water heating. It is also a major primary energy input into the Industrial sector, and thus the price of natural gas has a very significant impact on the competitiveness of some U.S. manufacturing industries. While natural gas provided 18% of the primary fuel for power generation in 2009,

**Figure 1.1 Sources and Use of Primary Energy Sources in the U.S. with Natural Gas Highlighted (quadrillion Btu), 2009**




Source: EIA, *Annual Energy Outlook, 2009* it provided 23% of the produced electricity, reflecting the higher efficiency of natural gas plants. As will be seen later in this report, natural gas-fired capacity represents far more than 23% of total power generating capacity, providing a real opportunity for early action in controlling $CO_2$ emissions.

### A Brief History of Natural Gas in the U.S.

The somewhat erratic history of natural gas in the U.S. over the last three decades or so provides eloquent testimony to the difficulties of forecasting energy futures, particularly for natural gas. It also serves as a reminder of the need for caution in the current period of supply exuberance.

The development of the U.S. natural gas market was facilitated by the emergence of an interstate natural gas pipeline system, supplying local distribution systems. This market structure was initially viewed as a natural monopoly and was subjected to cost-of-service regulation by both the Federal government and the states. Natural gas production and use grew considerably under this framework in the 1950s, 1960s, and into the 1970s.

Then came a perception of supply scarcity. After the first oil embargo, energy consumers sought to switch to natural gas. However, the combination of price controls and tightly regulated natural gas markets dampened incentives for domestic gas development, contributing to a perception that U.S. natural gas resources were limited. In 1978, convinced that the U.S. was running out of natural gas, Congress passed the Power Plant and Industrial Fuel Use Act (FUA) that essentially outlawed the building of new gas-fired power plants. Between 1978 and 1987 (the year the FUA was repealed), the U.S. added 172 Gigawatts (GW) of net power generation capacity. Of this, almost 81 GW was new coal capacity, around 26% of today's entire coal fleet. About half of the remainder was nuclear power.

By the mid 1990s, wholesale electricity markets and wellhead natural gas prices had been deregulated; new, highly efficient and relatively inexpensive combined cycle gas turbines had been deployed; and new upstream technologies had enabled the development of offshore natural gas resources. This contributed to the perception that domestic natural gas supplies were sufficient to increase the size of the U.S. natural gas market from around 20 Tcf/year to much higher levels. New gas-fired power capacity was added at a rapid pace.

Between 1989 after the repeal of the FUA and 2009, the U.S. added 306 GW of generation capacity, 88% of which was gas fired and 4% was coal fired.[2] Today, the nameplate capacity of this gas-fired generation is significantly under utilized, and the anticipated large increase in natural gas use has not materialized.

By the turn of the 21st century, a new set of concerns arose about the adequacy of domestic natural gas supplies. Conventional supplies were in decline, unconventional natural gas resources remained expensive and difficult to develop, and overall confidence in gas plummeted. Natural gas prices started to rise, becoming more closely linked to the oil price, which itself was rising. Periods of significant natural gas price volatility were experienced.

This rapid buildup in natural gas price, and perception of long-term shortage, created economic incentives for the accelerated development of an LNG import infrastructure. Since 2000, North America's rated LNG capacity has expanded from approximately 2.3 billion cubic feet (Bcf)/day to 22.7 Bcf/day, around 35% of the nation's average daily requirement.

This expansion of LNG capacity coincided with an overall rise in the natural gas price and the market diffusion of technologies to develop affordable unconventional gas. The game-changing potential of these technologies, combined with the large unconventional resource base, has become more obvious over the last few years, radically altering the U.S. supply picture. We have once again returned to a period where supply is seen to be abundant. New LNG import capacity goes largely unused at present, although it provides a valuable supply option for the future.

These cycles of perceived "feast and famine" demonstrate the genuine difficulty of forecasting the future and providing appropriate policy support for natural gas production and use. They underpin the efforts of this study to account for this uncertainty in an analytical manner.

### Major Uncertainties

Looking forward, we anticipate policy and geopolitics, along with resource economics and technology developments, will continue to play a major role in determining global supply and market structures. Thus, any analysis of the future of natural gas must deal explicitly with multiple uncertainties:

- *The extent and nature of the greenhouse gas (GHG) mitigation measures that will be adopted*: the U.S. legislative response to the climate threat has proved quite challenging. However, the Environmental Protection Agency (EPA) is developing regulations under the Clean Air Act, and a variety of local, state, and regional GHG limitation programs have been put in place. At the international level, reliance on a system of voluntary national pledges of emission reductions by 2020, as set out initially in the Copenhagen Accord, leaves uncertainty concerning the likely structure of any future agreements that may emerge to replace the Kyoto Protocol. The absence of a clear international regime for mitigating GHG emissions in turn raises questions about the likely stringency of national policies in both industrialized countries and major emerging economies over coming decades.

- *The likely technology mix in a carbon-constrained world*, particularly in the power sector: the relative costs of different technologies may shift significantly in response to RD&D, and a $CO_2$ emissions price will affect the relative costs. Moreover, the technology mix will be affected by regulatory and subsidy measures that will skew economic choices.

- *The ultimate size and production cost of the natural gas resource base*, and the environmental acceptability of production methods: much remains to be learned about the performance of shale gas plays, both in the U.S. and in other parts of the world. Indeed, even higher risk and less well-defined unconventional natural gas resources, such as methane hydrates, could make a contribution to supply in the later decades of the study's time horizon.

- *The evolution of international natural gas markets*: very large natural gas resources are to be found in several areas outside the U.S., and the role of U.S. natural gas will be influenced by the evolution of this market — particularly the growth and efficiency of trade in LNG. Only a few years back, U.S. industry was investing in facilities for substantial LNG imports. The emergence of the domestic shale gas resource has depressed this business in the U.S., but in the future, the nation may again look to international markets.

Of these uncertainties, the last three can be explored by applying technically grounded analysis: lower cost for carbon capture and storage (CCS), renewables, and nuclear power; producible resources of different levels; and regional versus global integrated markets. In contrast, the shape and size of GHG mitigation measures are likely to be resolved only through complex ongoing political discussions at the national level in the major emitting countries and through multilateral negotiations.

The analysis in this study is based on three policy scenarios:

1. A business-as-usual case, with no significant carbon constraints;

2. GHG emissions pricing, through a cap-and-trade system or emissions tax, leading to a 50% reduction in U.S. emissions below the 2005 level, by 2050.

3. GHG reduction via U.S. regulatory measures without emissions pricing: a renewable portfolio standard; and measures forcing the retirement of some coal plants.

Our analysis is long term in nature, with a 2050 time horizon. We do not attempt to make detailed short-term projections of volumes, prices, or price volatility, but rather focus on the long-term consequences of the carbon mitigation scenarios outlined above, taking into account the manifold uncertainties in a highly complex and interdependent energy system.

## MAJOR FINDINGS AND RECOMMENDATIONS

In the following section we summarize the major findings and recommendations for each chapter of the report.

### Supply

Globally, there are abundant supplies of natural gas, much of which can be developed at relatively low cost. The mean projection of remaining recoverable resource in this report is 16,200 Tcf, 150 times current annual global natural gas consumption, with low and high projections of 12,400 Tcf and 20,800 Tcf, respectively. Of the mean projection, approximately 9,000 Tcf could be developed economically with a natural gas price at or below $4/Million British thermal units (MMBtu) at the export point.

Unconventional natural gas, and particularly shale gas, will make an important contribution to future U.S. energy supply and $CO_2$ emission-reduction efforts. Assessments of the recoverable volumes of shale gas in the U.S. have increased dramatically over the last five years, and continue to grow. The mean projection of the recoverable shale gas resource in this report is approximately 650 Tcf, with low and high projections of 420 Tcf and 870 Tcf, respectively. Of the mean projection, approximately 400 Tcf could be economically developed with a natural gas price at or below $6/MMBtu at the wellhead. While the pace of shale technology development has been very rapid over the past few years, there are still many scientific and technological challenges to overcome before we can be confident that this very large resource base is being developed in an optimum manner.

Although there are large supplies, global conventional natural gas resources are concentrated geographically, with 70% in three countries: Qatar, Iran, and Russia. There is considerable potential for unconventional natural gas supply outside North America, but these resources are largely unproven with very high resource uncertainty. Nevertheless, unconventional supplies could provide a major opportunity for diversification and improved security of supply in some parts of the world.

The environmental impacts of shale development are challenging but manageable. Shale development requires large-scale fracturing of the shale formation to induce economic production rates. There has been concern that these fractures can also penetrate shallow freshwater zones and contaminate them with fracturing fluid, but there is no evidence that this is occurring. There is, however, evidence of natural gas migration into freshwater zones in some areas, most likely as a result of substandard well completion practices by a few operators. There are additional environmental challenges in the area of water management, particularly the effective disposal of fracture fluids. Concerns with this issue are particularly acute in regions that have not previously experienced large-scale oil and natural gas development, especially those overlying the massive Marcellus shale, and do not have a well-developed subsurface water disposal infrastructure. It is essential that both large and small companies follow industry best practices; that water supply and disposal are coordinated on a regional basis; and that improved methods are developed for recycling of returned fracture fluids.

Natural gas trapped in the ice-like form known as methane hydrate represents a vast potential resource for the long term. Recent research is beginning to provide better definition of the overall resource potential, but many issues remain to be resolved. In particular, while there have been limited production tests, the long-term producibility of methane hydrates remains unproven, and sustained research will be required.

**MAJOR RECOMMENDATIONS**

**Government-supported research on the fundamental challenges of unconventional natural gas development, particularly shale gas, should be greatly increased in scope and scale. In particular, support should be put in place for a comprehensive and integrated research program to build a system-wide understanding of all subsurface aspects of the U.S. shale resource. In addition, research should be pursued to reduce water usage in fracturing and to develop cost-effective water recycling technology.**

**A concerted coordinated effort by industry and government, both state and Federal, should be organized so as to minimize the environmental impacts of shale gas development through both research and regulation. Transparency is key, both for fracturing operations and for water management. Better communication of oil- and gas-field best practices should be facilitated. Integrated regional water usage and disposal plans and disclosure of hydraulic fracture fluid components should be required.**

**The U.S. should support unconventional natural gas development outside U.S., particularly in Europe and China, as a means of diversifying the natural gas supply base.**

**The U.S. government should continue to sponsor methane hydrate research, with a particular emphasis on the demonstration of production feasibility and economics.**

### U.S. Natural Gas Production, Use, and Trade: Potential Futures

In a carbon-constrained world, a level playing field — a $CO_2$ emissions price for all fuels without subsidies or other preferential policy treatment — maximizes the value to society of the large U.S. natural gas resource.

Under a scenario with 50% $CO_2$ reductions to 2050, using an established model of the global economy and natural gas cost curves that include uncertainty, the principal effects of the associated $CO_2$ emissions price are to lower energy demand and displace coal with natural gas in the electricity sector. *In effect, gas-fired power sets a competitive benchmark against which other technologies must compete in a lower carbon environment*. A major uncertainty that could impact this picture in the longer term is technology development that lowers the costs of alternatives, in particular, renewables, nuclear, and CCS.

A more stringent $CO_2$ reduction of, for example, 80% would probably require the complete de-carbonization of the power sector. This makes it imperative that the development of competing low-carbon technology continues apace, including CCS for both coal and natural gas. It would be a significant error of policy to crowd out the development of other, currently more costly, technologies because of the new assessment of the natural gas supply. Conversely, it would also be a mistake to encourage, via policy and long-term subsidy, more costly technologies to crowd out natural gas in the short to medium term, as this could significantly increase the cost of $CO_2$ reduction.

The evolution of global natural gas markets is unclear; but under some scenarios, the U.S. could import 50% or more of its natural gas by 2050, despite the significant new resources created in the last few years. Imports can prevent natural gas-price inflation in future years.

**MAJOR RECOMMENDATIONS**

**To maximize the value to society of the substantial U.S. natural gas resource base, U.S. $CO_2$ reduction policy should be designed to create a "level playing field," where all energy technologies can compete against each other in an open marketplace conditioned by legislated $CO_2$ emissions goals. A $CO_2$ price for all fuels without long-term subsidies or other preferential policy treatment is the most effective way to achieve this result.**

**In the absence of such policy, interim energy policies should attempt to replicate as closely as possible the major consequences of a "level playing field" approach to carbon-emissions reduction. At least for the near term, that would entail facilitating energy demand reduction and displacement of some coal generation with natural gas.**

**Natural gas can make an important contribution to GHG reduction in coming decades, but investment in low-emission technologies, such as nuclear, CCS, and renewables, should be actively pursued to ensure that a mitigation regime can be sustained in the longer term.**

### Natural Gas for Electric Power

In the U.S., around 30% of natural gas is consumed in the electric power sector. Within the power sector, gas-fired power plants play a critical role in the provision of peaking capacity, due to their inherent ability to respond rapidly to changes in demand. In 2009, 23% of the total power generated was from natural gas, while natural gas plants represented over 40% of the total generating capacity.

In a carbon-constrained world, the power sector represents the best opportunity for a significant increase in natural gas demand, in direct competition with other primary energy sources. Displacement of coal-fired power by gas-fired power over the next 25 to 30 years is the most cost-effective way of reducing $CO_2$ emissions in the power sector.

As a result of the boom in the construction of gas-fired power plants in the 1990s, there is a substantial amount of underutilized NGCC capacity in the U.S. today. In the short term, displacement of coal-fired power by gas-fired power provides an opportunity to reduce $CO_2$ emissions from the power sector by about 20%, at a cost of less than \$20/ton of $CO_2$ avoided. This displacement would use existing generating capacity, and would, therefore, require little in the way of incremental capital expenditure for new generation capacity. It would also significantly reduce pollutants such as sulfur dioxide ($SO_2$), nitrous oxide ($NO_X$), particulates, and mercury (Hg).

Natural gas-fired power generation provides the major source of backup to intermittent renewable supplies in most U.S. markets. If policy support continues to increase the supply of intermittent power, then, in the absence of affordable utility-scale storage options, additional natural gas *capacity* will be needed to provide system reliability. In some markets, existing regulation does not provide the appropriate incentives to build incremental capacity with low load factors, and regulatory changes may be required.

In the short term, where a rapid increase in renewable generation occurs without any adjustment to the rest of the system, increased renewable power displaces gas-fired power generation and thus reduces demand for natural gas in the power sector. In the longer term, where the overall system can adjust through plant retirements and new construction, increased renewables displace baseload generation. This could mean displacement of coal, nuclear, or NGCC generation, depending on the region and policy scenario under consideration. For example, in the 50% $CO_2$ reduction scenario described earlier, where gas-fired generation drives out coal generation, increased renewable penetration as a result of cost reduction or government policy will reduce natural gas generation on a nearly one-for-one basis.

**MAJOR RECOMMENDATIONS**

**The displacement of coal generation with NGCC generation should be pursued as the most practical near-term option for significantly reducing $CO_2$ emissions from power generation.**

**In the event of a significant penetration of intermittent renewable production in the generation technology mix, policy and regulatory measures should be developed to facilitate adequate levels of investment in natural gas generation capacity to ensure system reliability and efficiency.**

## END-USE GAS DEMAND

In the U.S., around 32% of all natural gas consumption is in the Industrial sector, where its primary uses are for boiler fuel and process heat; and 35% of use is in the Residential and Commercial sectors, where its primary application is space heating. Only 0.15% of natural gas is used as a vehicle transportation fuel.

### Industrial, Commercial, and Residential

Within the Industrial sector, there are opportunities for improved efficiency of the Industrial boiler fleet, replacing less-efficient natural gas boilers with high-efficiency, or super-high efficiency boilers with conversion efficiencies up to 94%. There are also opportunities to improve the efficiency of natural gas use in process heating and to reduce process heating requirements through changes in process technologies and material substitutions.

Our analysis suggests that conversion of coal-fired boilers in the Industrial sector to high-efficiency gas boilers could provide a cost-effective option for compliance with new hazardous air pollutant reductions and create significant $CO_2$ reduction opportunities at modest cost, with a potential to increase natural gas demand by up to 0.9 Tcf/year.

Natural gas and natural gas liquids (NGL) are a principal feedstock in the chemicals industry and a growing source of hydrogen production for petroleum refining. Our analysis of selected cases indicates that a robust domestic market for natural gas and NGLs will improve the competitiveness of manufacturing industries dependent on these inputs.

Natural gas has significant advantages in the Residential and Commercial sectors due in part to its cleanliness and life cycle energy efficiency. However, understanding the comparative cost effectiveness and $CO_2$ impacts of different energy options is complex. Comparison of end-use or "site" energy efficiencies can be misleading, since it does not take into account full system energy use and emissions (such as the efficiency and emissions of electricity generation). However, quantitatively accounting for the full system impacts from the "source" can be challenging, requiring a complex end-to-end, full fuel cycle (FFC) analysis that is not generally available to the consumer or to the policy maker.

Consumer and policy maker choices are further complicated by the influence of local climatic conditions and regional energy markets. The primary energy mix of the regional generation mix fundamentally affects "site versus source" energy and emissions comparisons. And the local climate has a major influence on the best choice of heating and cooling systems, particularly the appropriate use of modern space conditioning technologies such as heat pumps. Consumer information currently available to consumers does not facilitate well-informed decision making.

Expanded use of combined heat and power (CHP) has considerable potential in the Industrial and large Commercial sectors. However, cost, complexity, and the inherent difficulty of balancing heat and power loads at a very small scale make residential CHP a much more difficult proposition.

**MAJOR RECOMMENDATIONS**

**Improved energy-efficiency metrics, which allow consumers to accurately compare direct fuel and electricity end uses on a full fuel cycle basis, should be developed.**

**Over time, these metrics should be tailored to account for geographical variations in the sources of electric power supply and local climate conditions.**

### Transportation

The ample domestic supply of natural gas has stimulated interest in its use in transportation. There are multiple drivers: the oil-natural gas price spread on an energy basis generally favors natural gas, and today that spread is at historically high levels; an opportunity to lessen oil dependence in favor of a domestically supplied fuel, including natural gas-derived liquid fuels with modest changes in vehicle and/or infrastructure requirements and reduced $CO_2$ emissions in direct use of natural gas.

CNG offers a significant opportunity in U.S. heavy-duty vehicles used for short-range operation (buses, garbage trucks, delivery trucks), where payback times are around three years or less and infrastructure issues do not impede development. However, for light passenger vehicles, even at 2010 oil–natural gas price differentials, high incremental costs of CNG vehicles lead to long payback times for the average driver, so significant penetration of CNG into the passenger fleet is unlikely in the short term. Payback periods could be reduced significantly if the cost of conversion from gasoline to CNG could be reduced to the levels experienced in other parts of the world such as Europe.

LNG has been considered as a transport fuel, particularly in the long-haul trucking sector. However, as a result of operational and infrastructure considerations as well as high incremental costs and an adverse impact on resale value, LNG does not appear to be an attractive option for general use. There may be an opportunity for LNG in the rapidly expanding segment of hub-to-hub trucking operations, where infrastructure and operational challenges can be overcome.

Energy density, ease of use, and infrastructure considerations make liquid fuels that are stable at room temperature a compelling choice in the Transportation sector. The chemical conversion of natural gas to liquid fuels could provide an attractive alternative to CNG. Several pathways are possible, with different options yielding different outcomes in terms of total system $CO_2$ emissions and cost. Conversion of natural gas to methanol, as widely practiced in the chemicals industry, could provide a cost-effective route to manufacturing an alternative, or supplement, to gasoline, while keeping $CO_2$ emissions at roughly the same level. Gasoline engines can be modified to run on methanol at modest cost.

**MAJOR RECOMMENDATIONS**

**The U.S. government should consider revision to its policies related to CNG vehicles, including how aftermarket CNG conversions are certified, with a view to reducing up-front costs and facilitating bi-fuel CNG-gasoline capacity.**

**The U.S. government should implement an open fuel standard that requires automobile manufacturers to provide tri-flex fuel (gasoline, ethanol, and methanol) operation in light-duty vehicles. Support for methanol fueling infrastructure should also be considered.**

### Infrastructure

The continental U.S. has a vast, mature, and robust natural gas infrastructure, which includes: over 300,000 miles of transmission lines; numerous natural gas-gathering systems; storage sites; processing plants; distribution pipelines; and LNG import terminals.

Several trends are having an impact on natural gas infrastructure. These include changes in U.S. production profiles, with supplies generally shifting from offshore Gulf of Mexico back to onshore; shifts in U.S. population, generally from the Northeast and Midwest to the South and West; and growth in global LNG markets, driven by price differences between regional markets.

The system generally responds well to market signals. Changing patterns of supply and demand have led to a significant increase in infrastructure development over the past few years with West to East expansions dominating pipeline capacity additions. Infrastructure limitations can temporarily constrain production in emerging production areas such as the Marcellus shale — but infrastructure capacity expansions are planned or underway. Demand increases and shifts in consumption and production are expected to require around $210 billion in infrastructure investment over the next 20 years.

Much of the U.S. pipeline infrastructure is old — around 25% of U.S. natural gas pipelines are 50 years old or older — and recent incidents demonstrate that pipeline safety issues are a cause for concern. The Department of Transportation (DOT) regulates natural gas pipeline safety and has required integrity management programs for transmission and distribution pipelines. The DOT also supports a small pipeline safety research program, which seems inadequate given the size and age of the pipeline infrastructure.

Increased use of natural gas for power generation has important implications for both natural gas and electric infrastructures, including natural gas storage. Historically, injections and withdrawals from natural gas storage have been seasonal. Increased use of natural gas for power generation may require new high-deliverability natural gas storage to meet more variable needs associated with power generation.

**MAJOR RECOMMENDATIONS**

**Analysis of the infrastructure demands associated with potential shift from coal to gas-fired power should be undertaken.**

**Pipeline safety technologies should be included in natural gas RD&D programs.**

## END-USE EMISSIONS VERSUS SYSTEM-WIDE EMISSIONS

When comparing GHG emissions for different energy sources, attention should be paid to the entire system. In particular, the potential for leakage of small amounts of methane in the production, treatment, and distribution of coal, oil, and natural gas has an effect on the total GHG impact of each fuel type. The modeling analysis in Chapter 3 addresses the system-wide impact, incorporating methane leakage from coal, oil, and natural gas production, processing, and transmission. In Chapter 5 we do not attempt to present detailed full-system accounting of $CO_2$ (equivalent) emissions for various end uses, although we do refer to its potential impact in specific instances.

The $CO_2$ equivalence of methane is conventionally based on a Global Warming Potential (GWP)[3] intended to capture the fact that each GHG has different radiative effects on climate and different lifetimes in the atmosphere. In our considerations, we follow the standard Intergovernmental Panel on Climate Change (IPCC) and EPA definition that has been widely employed for 20 years. Several recently published life cycle emissions analyses do not appear to be comprehensive, use common assumptions, or recognize the progress made by producers to reduce methane emissions, often to economic benefit. We believe that a lot more work is required in this area before a common understanding can be reached. Further discussion can be found in Appendix 1A.

**MAJOR RECOMMENDATIONS**

**The EPA and the U.S. Department of Energy (DOE) should co-lead a new effort to review, and update as appropriate, the methane emission factors associated with natural gas production, transmission, storage, and distribution. The review should have broad-based stakeholder involvement and should seek to reach a consensus on the appropriate methodology for estimating methane emissions rates. The analysis should, to the extent possible: reflect actual emissions measurements; address fugitive emissions for coal and oil as well as natural gas; and reflect the potential for cost-effective actions to prevent fugitive emissions and venting of methane.**

## MARKETS AND GEOPOLITICS

The physical characteristics of natural gas, which create a strong dependence on pipeline transportation systems, have led to local markets for natural gas, in contrast to the global markets for oil.

There are three distinct regional gas markets: North America, Europe, and Asia, with more localized markets elsewhere. The U.S. gas market is mature and sophisticated, and functions well, with a robust spot market. Within the U.S. market, the price of oil (which is set globally) compared to the price of natural gas (which is set regionally) is very important in determining market share when there is the opportunity for substitution. Over the last decade or so, when oil prices have been high, the ratio of the benchmark West Texas Intermediate oil price to the Henry Hub natural gas price has been consistently higher than any of the standard rules of thumb.

International natural gas markets are in the early stages of integration, with many impediments to further development. While increased LNG trade has started to connect these markets, they remain largely distinct with respect to supply patterns, pricing and contract structures, and market regulation. If a more integrated market evolves, with nations pursuing gas production and trade on an economic basis, there will be rising trade among the current regional markets and the U.S. could become a substantial net importer of LNG in future decades.

Greater international market liquidity would be beneficial to U.S. interests. U.S. prices for natural gas would be lower than under current regional markets, leading to more gas use in the U.S. Greater market liquidity would also contribute to security by enhancing diversity of global supply and resilience to supply disruptions for the U.S. and its allies. These factors ameliorate security concerns about import dependence.

As a result of the significant concentration of conventional gas resources globally, policy and geopolitics play a major role in the development of global supply and market structures. Consequently, since natural gas is likely to play a greater role around the world, natural gas issues will appear more frequently on the U.S. energy and security agenda. Some of the specific security concerns are:

- Natural gas dependence, including that of allies, could constrain U.S. foreign policy options, especially in light of the unique American international security responsibilities.

- New market players could introduce impediments to the development of transparent markets.

- Competition for control of natural gas pipelines and pipeline routes is intense in key regions.

- Longer supply chains increase the vulnerability of the natural gas infrastructure.

### MAJOR RECOMMENDATIONS

**The U.S. should pursue policies that encourage the development of an efficient and integrated global gas market with transparency and diversity of supply.**

**Natural gas issues should be fully integrated into the U.S. energy and security agenda, and a number of domestic and foreign policy measures should be taken, including:**

- **integrating energy issues fully into the conduct of U.S. foreign policy, which will require multiagency coordination with leadership from the Executive Office of the President;**
- **supporting the efforts of the International Energy Agency (IEA) to place more attention on natural gas and to incorporate the large emerging markets (such as China, India, and Brazil) into the IEA process as integral participants;**
- **sharing know-how for the strategic expansion of unconventional resources; and**
- **advancing infrastructure physical- and cyber-security as the global gas delivery system becomes more extended and interconnected.**

## RD&D

There are numerous RD&D opportunities to address key objectives for natural gas supply, delivery, and end use:

- improve the long-term economics of resource development as an important contributor to the public good;
- reduce the environmental footprint of natural gas production, delivery, and use;
- expand current use and create alternative applications for public policy purposes, such as emissions reductions and diminished oil dependence;
- improve safety and operation of natural gas infrastructure;
- improve the efficiency of natural gas conversion and end use so as to use the resource most effectively.

Historically, RD&D funding in the natural gas industry has come from a variety of sources, including private industry, the DOE, and private/public partnerships. In tandem with limited tax credits, this combination of support played a major role in development of unconventional gas. It has also contributed to more efficient end use, for example in the development of high-efficiency gas turbines.

Today government-funded RD&D for natural gas is at very low levels. The elimination of rate-payer funded RD&D has not been compensated by increased DOE appropriations or by a commensurate new revenue stream outside the appropriations process. The total public and public-private funding for natural gas research is down substantially from its peak and is more limited in scope, even as natural gas takes a more prominent role in a carbon-constrained world.

While natural gas can provide a cost-effective bridge to a low carbon future, it is vital that efforts continue to improve the cost and efficiency of low or zero carbon technologies for the longer term. This will require sustained RD&D and subsidies of limited duration to encourage early deployment.

### MAJOR RECOMMENDATIONS

**The Administration and Congress should support RD&D focused on environmentally responsible domestic natural gas supply. This should entail both a renewed DOE program, weighted towards basic research, and a complementary industry-led program, weighted towards applied research, development, and demonstration, that is funded through an assured funding stream tied to energy production, delivery, and use. The scope of the program should be broad, from supply to end use.**

**Support should be provided through RD&D, and targeted subsidies of limited duration, for low-emission technologies that have the prospect of competing in the long run. This would include renewables, CCS for both coal and gas generation, and nuclear power.**

## CONCLUSION

Over the past few years, the U.S. has developed an important new natural gas resource that fundamentally enhances the nation's long-term gas supply outlook. Given an appropriate regulatory environment, which seeks to place all lower carbon energy sources on a level competitive playing field, domestic supplies of natural gas can play a very significant role in reducing U.S. $CO_2$ emissions, particularly in the electric power sector. This lowest-cost strategy of $CO_2$ reduction allows time for the continued development of more cost-effective low or zero carbon energy technology for the longer term, when gas itself is no longer sufficiently low carbon to meet more stringent $CO_2$ reduction targets. The newly realized abundance of low-cost gas provides an enormous potential benefit to the nation, providing a cost-effective bridge to a secure and low carbon future. It is critical that the additional time created by this new resource is spent wisely, in creating lower-cost technology options for the longer term, and thereby ensuring that the natural gas bridge has a safe landing place in a low carbon future.

## NOTES

[1]One quadrillion Btu (or "quad") is 1015 or 1,000,000,000,000,000 British thermal units. Since one standard cubic foot of gas is approximately 1,000 Btu, then 1 quad is approximately 1 Tcf of gas.

[2]EIA 2009 Annual Energy Review, Figure 45.

[3]Global-warming potential (GWP) is a relative measure of how much heat a given greenhouse gas traps in the atmosphere.

# Chapter 2: Supply

## INTRODUCTION AND CONTEXT

In this chapter, we discuss various aspects of natural gas supply: how much natural gas exists in the world; at what rate can it be produced; and what it will cost to develop. Following the introduction and definitions, we look at production history, resource volumes, and supply costs for natural gas — first from a global perspective, and then focusing in more detail on the U.S., paying particular attention to the prospects for shale gas. We then discuss the science and technology of unconventional gas, the environmental impacts of shale gas development, and finally the prospects for methane hydrates.

## NATURAL GAS AND THE RECOVERY PROCESS

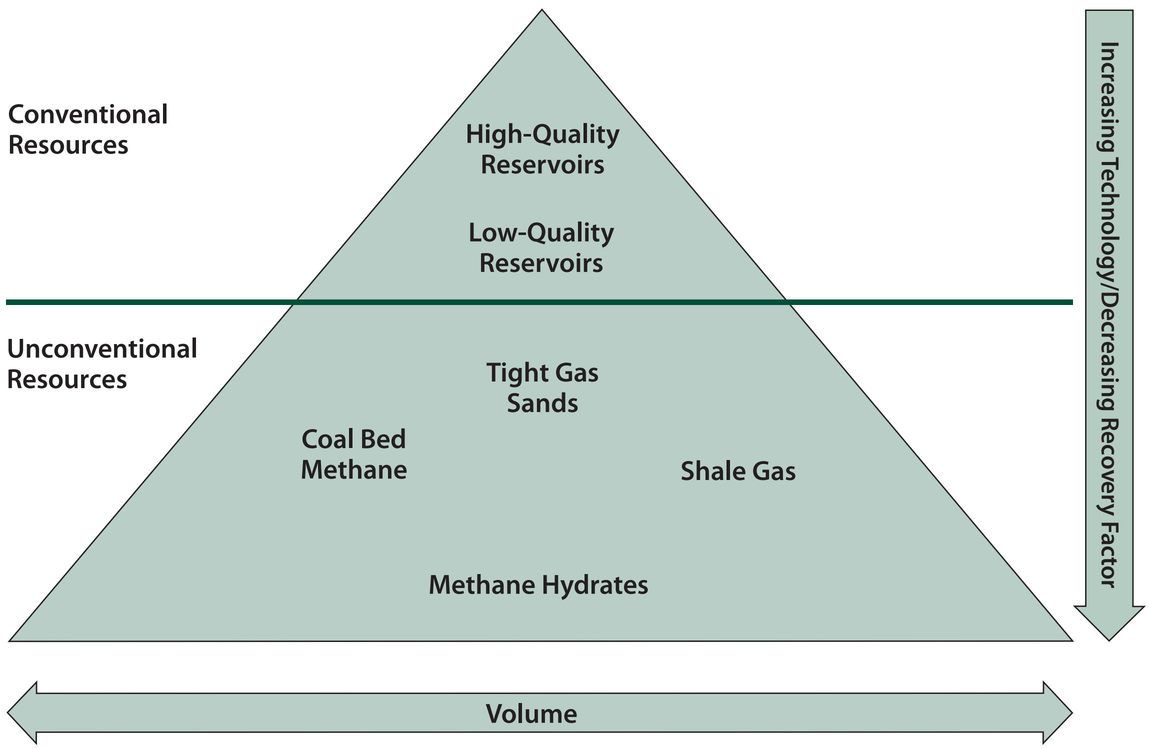
The primary chemical component of natural gas is methane, the simplest and lightest hydrocarbon molecule, comprised of four hydrogen (H) atoms bound to a single carbon (C) atom. In chemical notation, this is expressed as $CH_4$ (the symbol for methane). Natural gas may also contain small proportions of heavier hydrocarbons: ethane ($C_2H_6$); propane ($C_3H_8$), and butane ($C_4H_{10}$); these heavier components are often extracted from the producing stream and marketed separately as natural gas liquids (NGL). In the gas industry, the term "wet gas" is used to refer to natural gas in its raw unprocessed state, while "dry gas" refers to natural gas from which the heavier components have been extracted.

Thermogenic[1] natural gas, which is formed by the application, over geological time, of enormous heat and pressure to buried organic matter, exists under pressure in porous rock formations thousands of feet below the surface of the earth. It exists in two primary forms: "associated gas" is formed in conjunction with oil, and is generally released from the oil as it is recovered from the reservoir to the surface — as a general rule the gas is treated as a by-product of the oil production process; in contrast, "non-associated gas" is found in reservoirs that do not contain oil, and is developed as the primary product. While associated gas is an important source, the majority of gas production is non-associated; 89% of the gas produced in the U.S. is non-associated.

Non-associated gas is recovered from the formation by an expansion process. Wells drilled into the gas reservoir allow the highly compressed gas to expand through the wells in a controlled manner, to be captured, treated, and transported at the surface. This expansion process generally leads to high recovery factors from conventional, good-quality gas reservoirs. If, for example, the average pressure in a gas reservoir is reduced from an initial 5,000 pounds per square inch (psi) to 1,000 psi over the lifetime of the field, then approximately 80% of the Gas Initially In Place (GIIP) will be recovered. This is in contrast to oil, where recovery factors of 30% to 40% are more typical.

Gas is found in a variety of subsurface locations, with a gradation of quality as illustrated in the resource triangle in Figure 2.1.

**Figure 2.1 GIIP as a Pyramid in Volume and Quality. Conventional reservoirs are at the top of the pyramid. They are of higher quality because they have high permeability and require less technology for development and production. The unconventional reservoirs lie below the conventional reservoirs in this pyramid. They are more abundant in terms of GIIP but are currently assessed as recoverable resources — and commercially developed — primarily in North America. They have lower permeability, require advanced technology for production, and typically yield lower recovery factors than conventional reservoirs.**

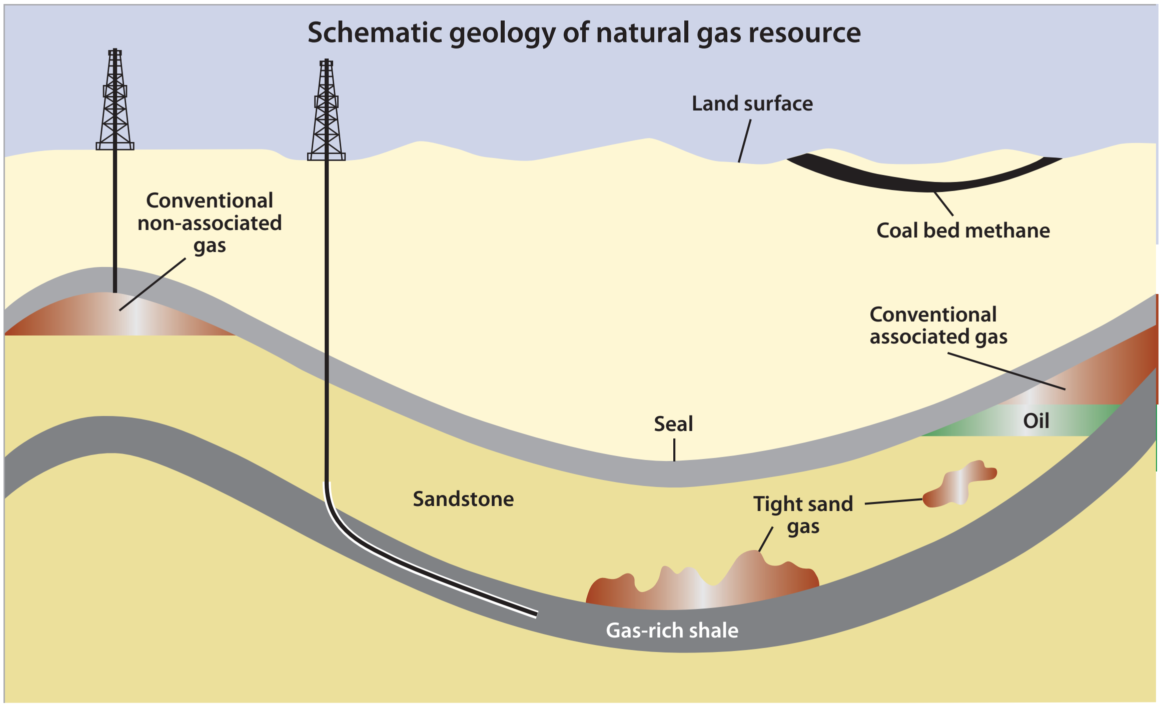



Adapted from Holditch 2006

Conventional resources exist in discrete, well-defined subsurface accumulations (reservoirs), with permeability[2] values greater than a specified lower limit. Such conventional gas resources can usually be developed using vertical wells, and generally yield the high recovery factors described above.

By contrast, unconventional resources are found in accumulations where permeability is low. Such accumulations include "tight" sandstone formations, coal beds (coal bed methane or CBM) and shale formations. Unconventional resource accumulations tend to be distributed over a larger area than conventional accumulations and usually require advanced technology such as horizontal wells or artificial stimulation in order to be economically productive; recovery factors are much lower — typically of the order of 15% to 30% of GIIP. The various resource types are shown schematically in Figure 2.2.

**Figure 2.2 Illustration of Various Types of Gas Resource**




Source: U.S. Energy Information Administration

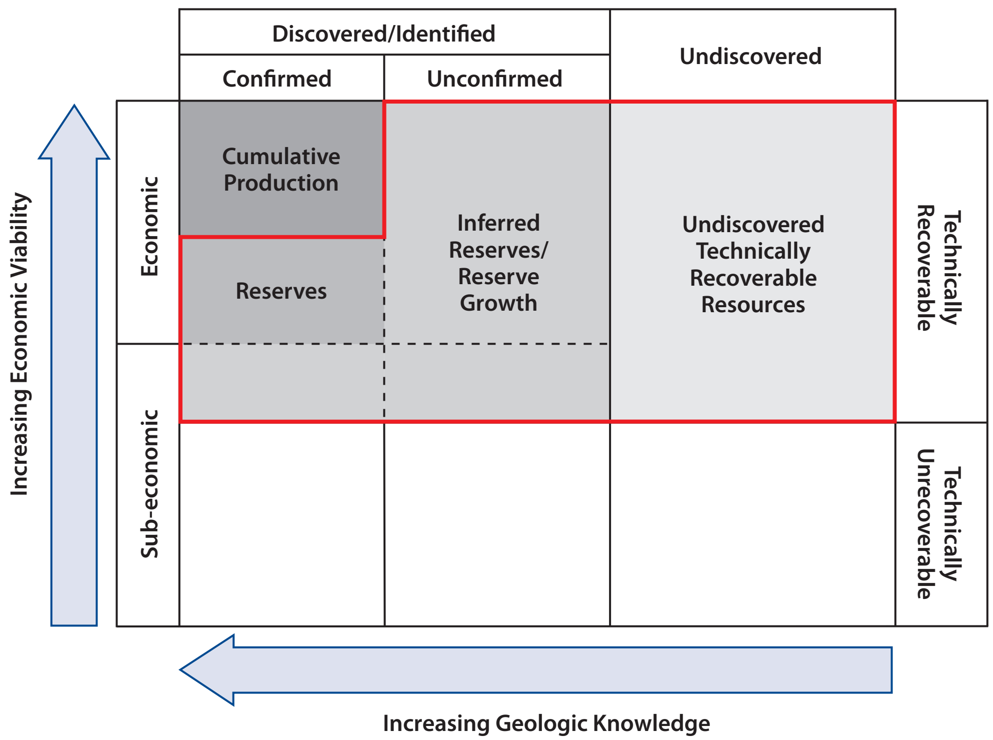
## RESOURCE DEFINITIONS

The complex cross-dependencies between geology, technology, and economics mean that the use of unambiguous terminology is critical when discussing natural gas supply. In this study, the term "resource" will refer to the sum of all gas volumes expected to be recoverable in the future, given specific technological and economic conditions. The resource can be disaggregated into a number of sub-categories; specifically, "proved reserves," "reserve growth" (via further development of known fields), and "undiscovered resources," which represent gas volumes that are expected to be discovered in the future via the exploration process.

*Gas resources are an economic concept — a function of many variables, in particular the cost of exploration, production, and transportation relative to the price of sale to users.*

Figure 2.3 illustrates how proved reserves, reserve growth, and undiscovered resources combine to form the "technically recoverable resource," that is, the total volume of natural gas that could be recovered in the future, using today's technology, ignoring economic constraints.

**Figure 2.3 Modified McKelvey Diagram, Showing the Interdependencies between Geology, Technology, and Economics and Their Impacts on Resource Classes; Remaining Technically Recoverable Resources Are Outlined in Red**




The methodology used in analyzing natural gas supply for this study places particular emphasis in two areas:

1. Treating gas resources as an economic concept — recoverable resources are a function of many variables, particularly the ultimate price that the market will pay. A set of supply curves has been developed using the ICF[3] Hydrocarbon Supply Model with volumetric and fiscal input data supplied by ICF International (ICF) and MIT. These curves describe the volume of gas that is economically recoverable for a given gas price. These curves form a primary input to the integrated economic modelling in Chapter 3 of this report.

2. Recognizing and embracing uncertainty — uncertainty exists around all resource estimates due to the inherent uncertainty associated with the underlying geological, technological, economic, and political conditions. The analysis of natural gas supply in this study has been carried out in a manner that frames any single point resource estimate within an associated uncertainty envelope, in order to illustrate the potentially large impact this ever-present uncertainty can have.

The volumetric data used as the basis of the analysis for both the supply curve development and the volumetric uncertainty analysis were compiled from a range of sources. In particular, use has been made of data from work at the United States Geological Survey (USGS), the Potential Gas Committee (PGC), the Energy Information Agency (EIA), the National Petroleum Council (NPC), and ICF.

## GLOBAL SUPPLY

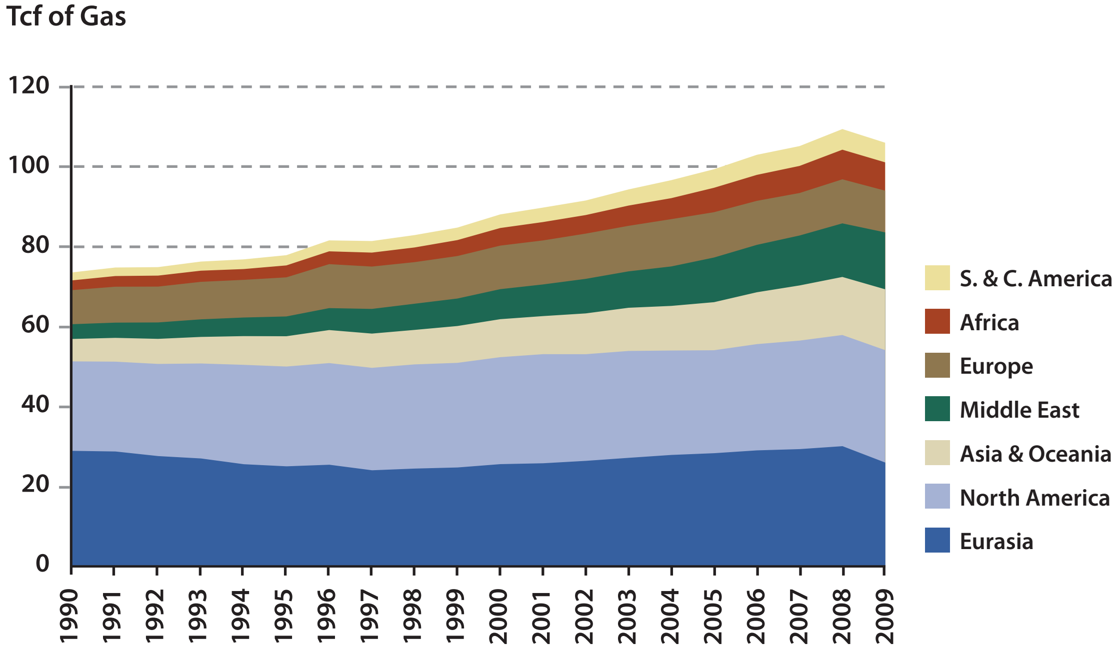
### Production Trends

Over the past two decades, global production of natural gas has grown significantly, rising by almost 42% overall from approximately 74 trillion cubic feet (Tcf)[4] in 1990 to 105 Tcf in 2009. This is almost twice the growth rate of global oil production, which increased by around 22% over the same period. Much of the gas production growth has been driven by the rapid expansion of production in areas that were not major gas producers prior to 1990. This trend is illustrated in Figure 2.4, which shows how growth in production from regions such as the Middle East, Africa, and Asia & Oceania has significantly outpaced growth in the traditional large producing regions, including North America and Eurasia (primarily Russia).

Figure 2.5 compares the 1990 and 2009 annual production levels for the 10 largest gas-producing nations (as defined by 2009 output). In addition to demonstrating the overwhelming scale of the U.S. and Russia compared to other producing countries, this figure illustrates the very significant growth rates in other countries. The substantial growth of new gas producing countries over the period reflects the relative immaturity of the gas industry on a global basis outside Russia and North America, the expansion of gas markets, and the rise in global cross-border gas trade.

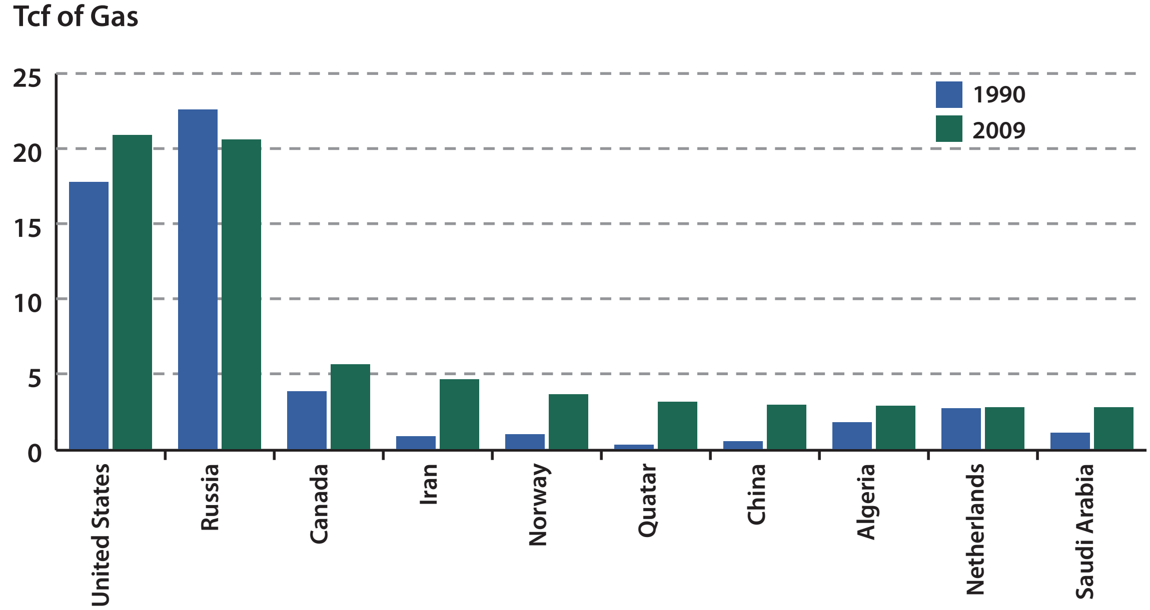
Between 1993 and 2008, global cross-border gas trade almost doubled, growing from around 18 Tcf (25% of global supply) to around 35 Tcf (32% of global supply). Most of the world's gas supply is transported from producing fields to market by pipeline. However, the increase in global gas trade has been accelerated by the growing use of Liquefied Natural Gas (LNG), which is made by cooling natural gas to around -162°C. Under these conditions, natural gas becomes liquid, with an energy density 600 times that of gas at standard temperature and pressure — and it can be readily transported over long distances in specialized ocean-going

**Figure 2.4 Trends in Annual Global Dry Gas Production by Region between 1990 and 2009**



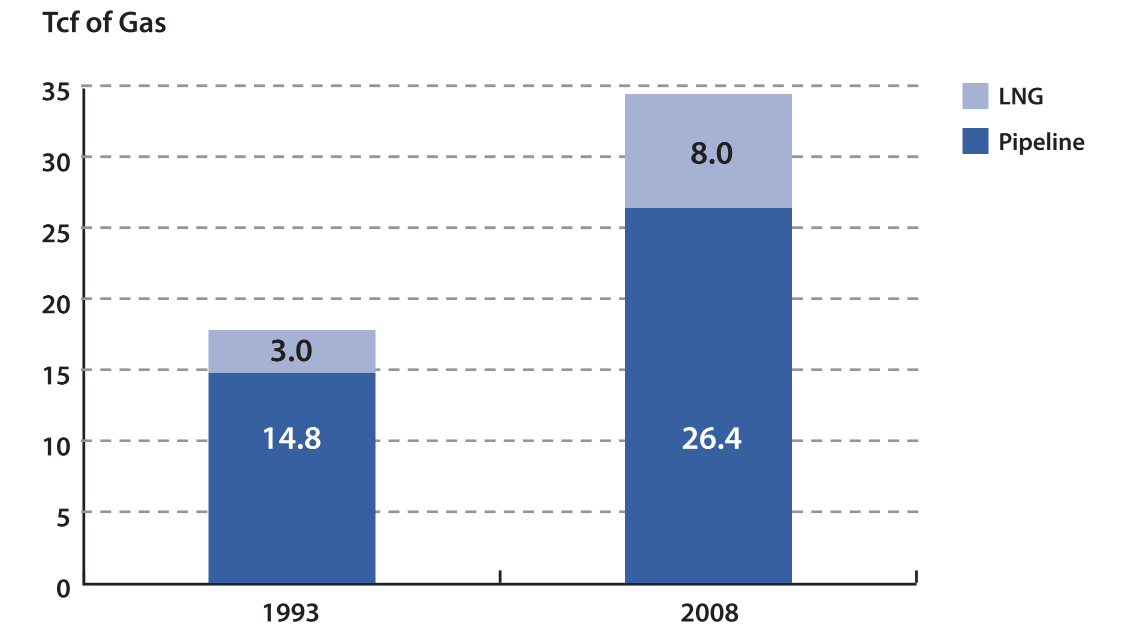

Source: MIT; U.S. Energy Information Administration

**Figure 2.5 Comparison of 1990 and 2009 Natural Gas Production Levels for the Top 10 Natural Gas Producing Nations (as defined by 2009 output)**




Source: MIT; U.S. Energy Information Administration

**Figure 2.6 Global Cross-Border Gas Trade**




Source: MIT; U.S. Energy Information Administration

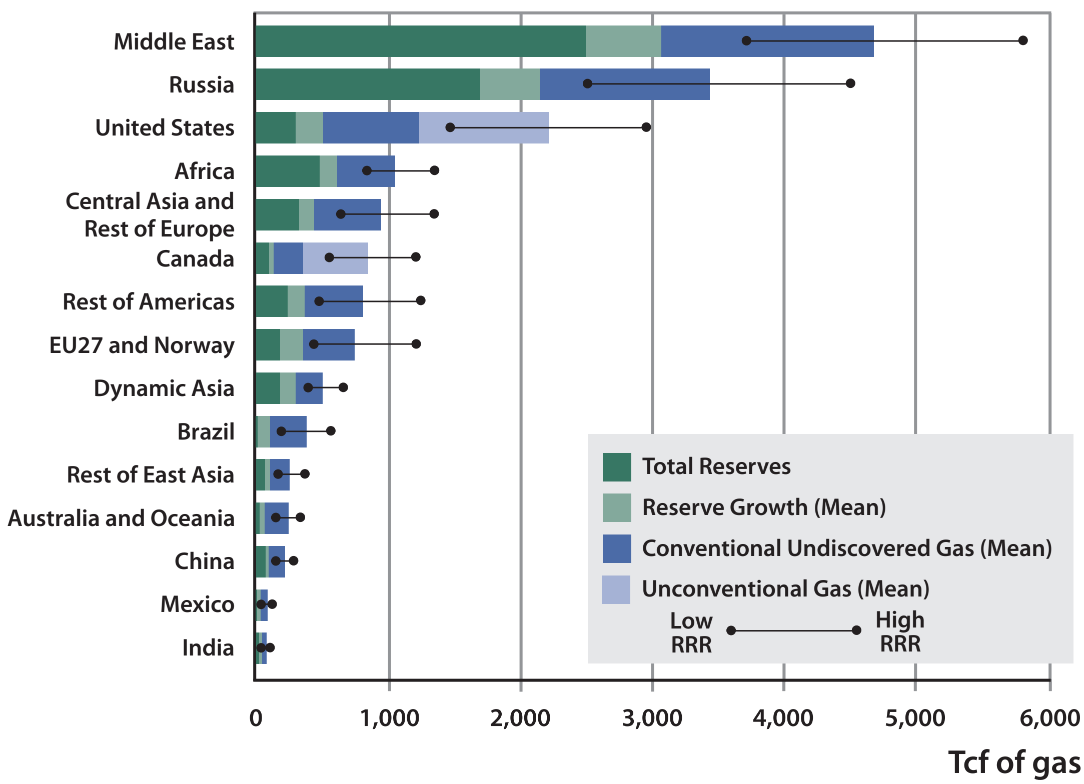
LNG tankers. Over this 15-year period, global gas trade doubled, while LNG trade increased even more rapidly, as shown in Figure 2.6.

## RESOURCES[5]

Global natural gas resources are abundant. The mean remaining resource base is estimated to be 16,200 Tcf, with a range between 12,400 Tcf (with a 90% probability of being exceeded) and 20,800 Tcf (with a 10% probability of being exceeded). The mean projection is 150 times the annual consumption in 2009. With the exception of Canada and the U.S., this estimate does not include any unconventional supplies. The global gas supply base is relatively immature; outside North America only 11% of the estimated ultimately recoverable conventional resources have been produced to date.

Figure 2.7 depicts the estimated remaining recoverable gas resources, together with estimated uncertainty,[6] broken down by regions as defined by the Emissions Prediction and Policy Analysis (EPPA) model employed in Chapter 3 of this report. Figure 2.8 depicts the geographical distribution of EPPA regions, together with the mean resource estimate for each region. The resources are comprised of three major components defined above: reserves, reserve growth, and yet-to-find resources. For the U.S. and Canada, we have also included a fourth category, unconventional resources. As discussed later, due to the very high levels of uncertainty at this stage, we have not included unconventional resource estimates for other regions.

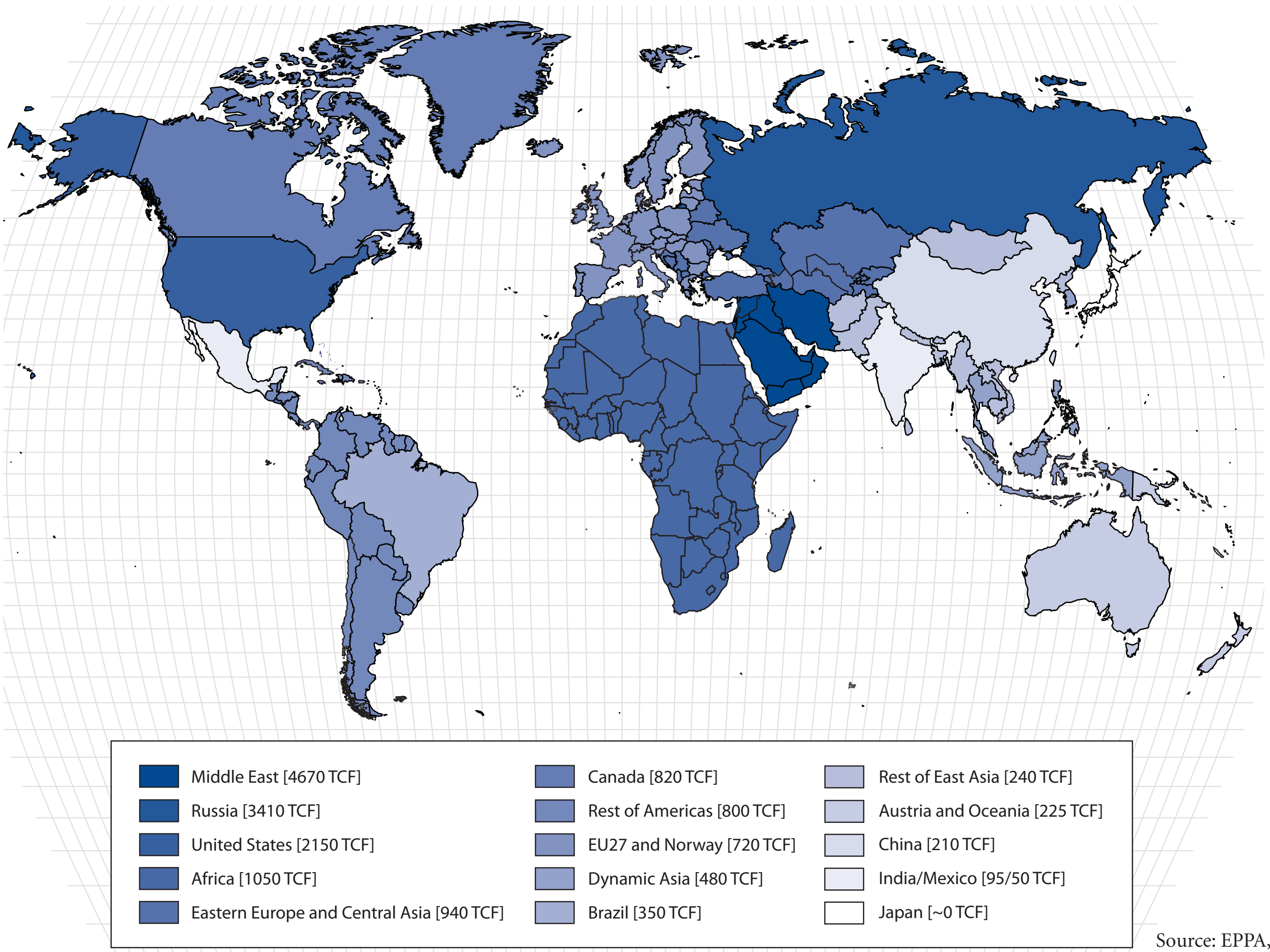
**Figure 2.7 Global Remaining Recoverable Gas Resource by EPPA Region, with Uncertainty**




Source: MIT analysis based on data and information from: Ahlbrandt *et al*. 2005; United States Geological Survey 2010; National Petroleum Council 2003; United States Geological Survey n.d.; Potential Gas Committee 1990; Attanasi & Coburn 2004; Energy Information Administration 2009

Although resources are large, the supply base is concentrated geographically, with an estimated 70% in only three regions: Russia, the Middle East (primarily Qatar and Iran), and North America (where North American resources also include unconventional gas). By some measures, global supplies of natural gas are even more geographically concentrated than oil supplies. Political considerations and individual country depletion policies play at least as big a role in global gas resource development as geology and economics, and dominate the evolution of the global gas market.

**Figure 2.8 Map of EPPA Regions, and Mean Resource Estimates**




Source: EPPA, MIT

## SUPPLY COSTS[7]

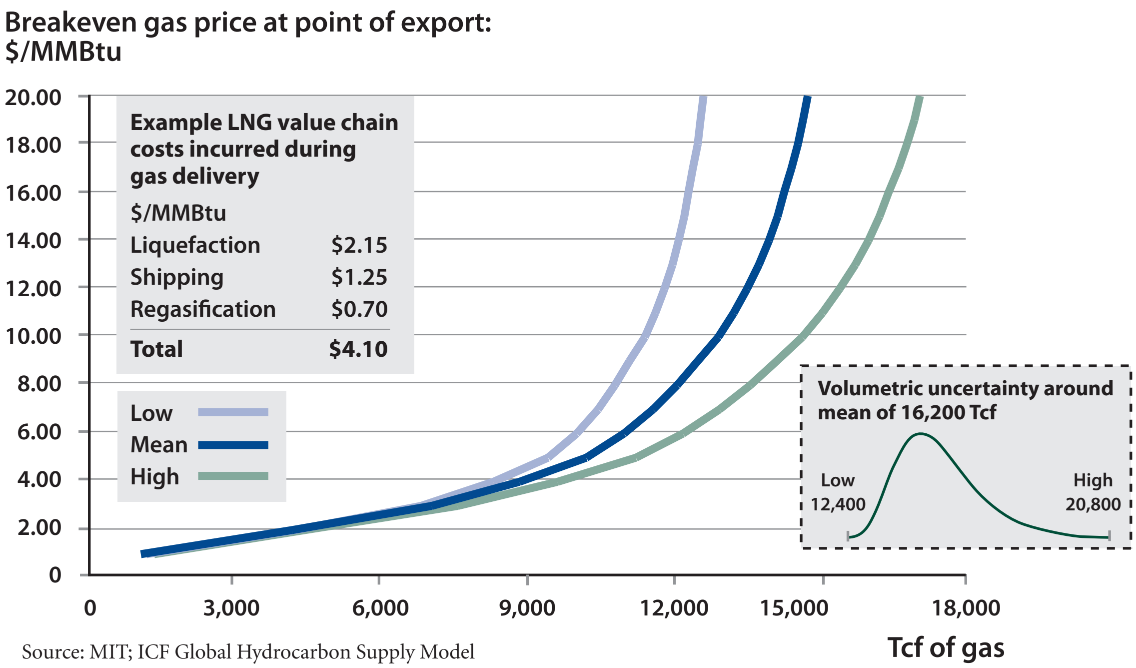
Figure 2.9 depicts a set of global supply curves, which describe the resources of gas that can be developed economically at given prices at the point of export. The higher the price, the more gas will ultimately be developed. Much of the global supply can be developed economically with relatively low prices at the wellhead or the point of export.[8] However, the cost of delivering this gas to market is generally considerably higher.

In contrast to oil, the total cost of delivering gas to international markets is strongly influenced by transportation costs, either via long-distance pipeline or as LNG. Transportation costs will obviously be a function of distance, but by way of illustration, resources that can be economically developed at a gas price of $1 or $2/million British thermal units (MMBtu) may well require an additional $3 to $5/MMBtu of transport costs to get to their ultimate destination. These high transportation costs are also a significant factor in the evolution of the global gas market.

Figure 2.10 depicts the mean gas supply curves for those EPPA regions that contain significant gas resources. Again, this illustrates the significant concentration of gas resources in the world.

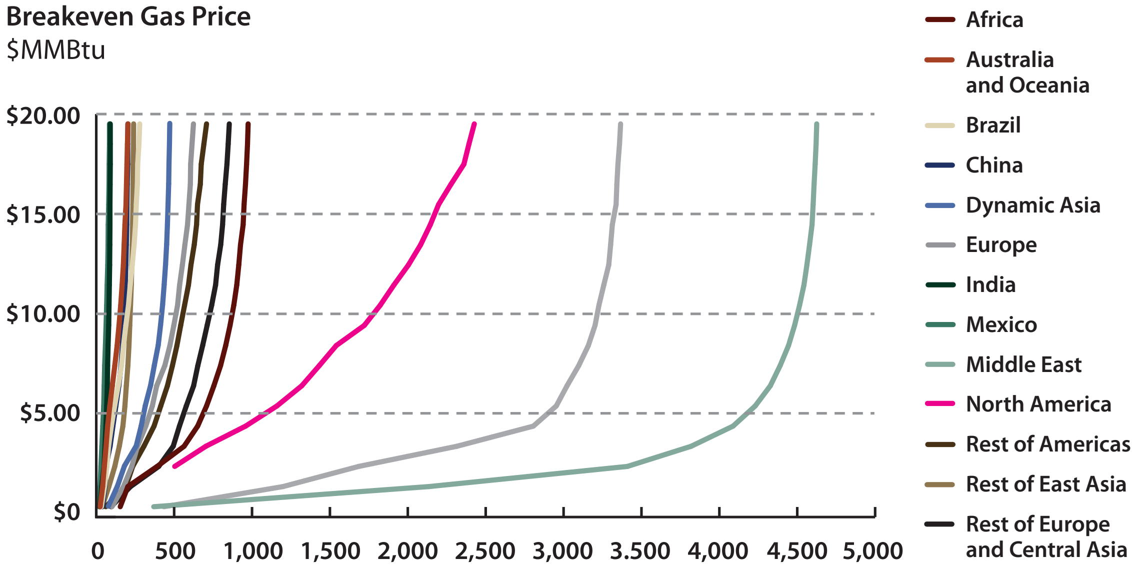
*In contrast to oil, the total cost of getting gas to international markets is strongly influenced by the cost of transportation — a significant factor in the evolution of the global gas market.*

**Figure 2.9 Global Gas Supply Cost Curve, with Uncertainty; 2007 Cost Base**




Source: MIT; ICF Global Hydrocarbon Supply Model

**Figure 2.10 Global Gas Supply Cost Curve by EPPA Region; 2007 Cost Base**




Source: MIT; ICF Global Hydrocarbon Supply Model

## UNCONVENTIONAL RESOURCES[9]

Outside of Canada and the U.S., there has been very little development of the unconventional gas supply base — indeed there has been little need when conventional resources are so abundant. But due to this lack of development, unconventional resource estimates are sparse and unreliable.

Based on an original estimate by Rogner[10], there may be of the order of 24,000 Tcf of unconventional GIIP outside North America. Applying a nominal 25% recovery factor, this would imply around 6,000 Tcf of unconventional recoverable resources. However, these global estimates are highly speculative, almost completely untested, and subject to very wide bands of uncertainty. There is a long-term need for basin-by-basin resource evaluation to provide credibility to the GIIP estimates and, most importantly, to establish realistic estimates of recoverable resource volumes and costs[11].

Given the concentrated nature of conventional supplies and the high costs of long-distance transportation, there may be considerable strategic and economic value in the development of unconventional resources in those regions that are currently gas importers, such as Europe and China. It would be in the strategic interest of the U.S. to see these indigenous supplies developed. As a market leader in this technology, the U.S. could play a significant role in facilitating this development.

**RECOMMENDATION**

**U.S. policy should encourage the strategic development of unconventional gas supplies in regions which currently depend on imported gas, in particular, Europe and China.**

## UNITED STATES SUPPLY

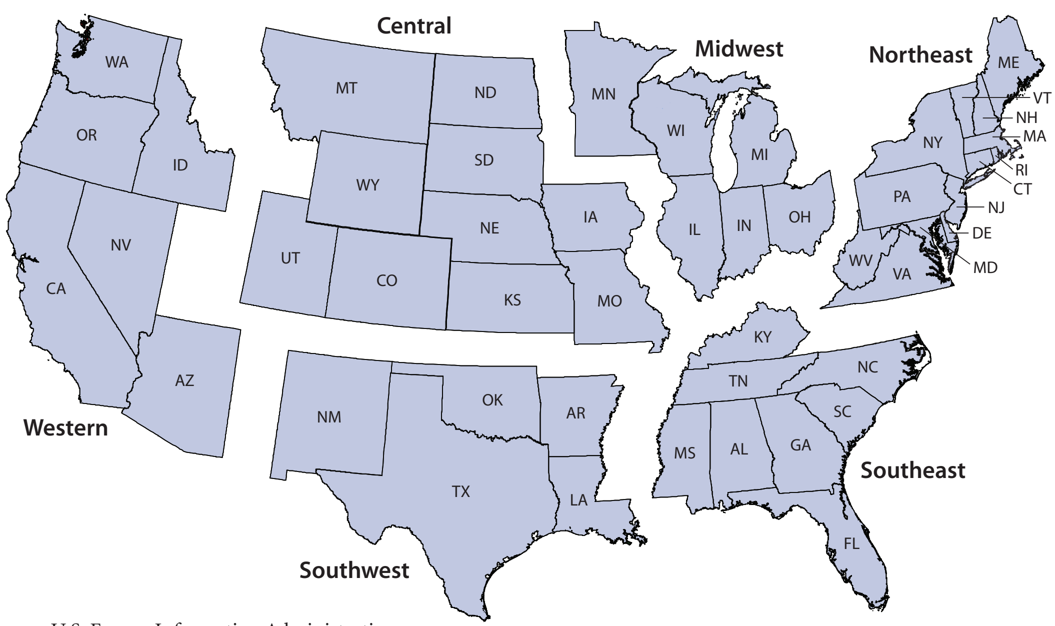
### Production Trends

There is significant geographical variation in U.S. natural gas production levels. For the purposes of this discussion of U.S. production, we will use the U.S. EIA pipeline regions (Figure 2.11).

Natural gas production in the U.S. has traditionally been associated with the Southwest region and the Gulf of Mexico. However, significant production also takes place in Alaska and in the Central region. In the case of Alaska, the vast majority of the gas is associated with oil production on the North Slope, and due to the lack of an export mechanism, this gas is re-injected to enhance recovery from Alaskan oil fields. These gas production volumes are therefore not included in the national gas production figures reported by the EIA. Small volumes of gas are exported from Alaska to Japan as LNG.

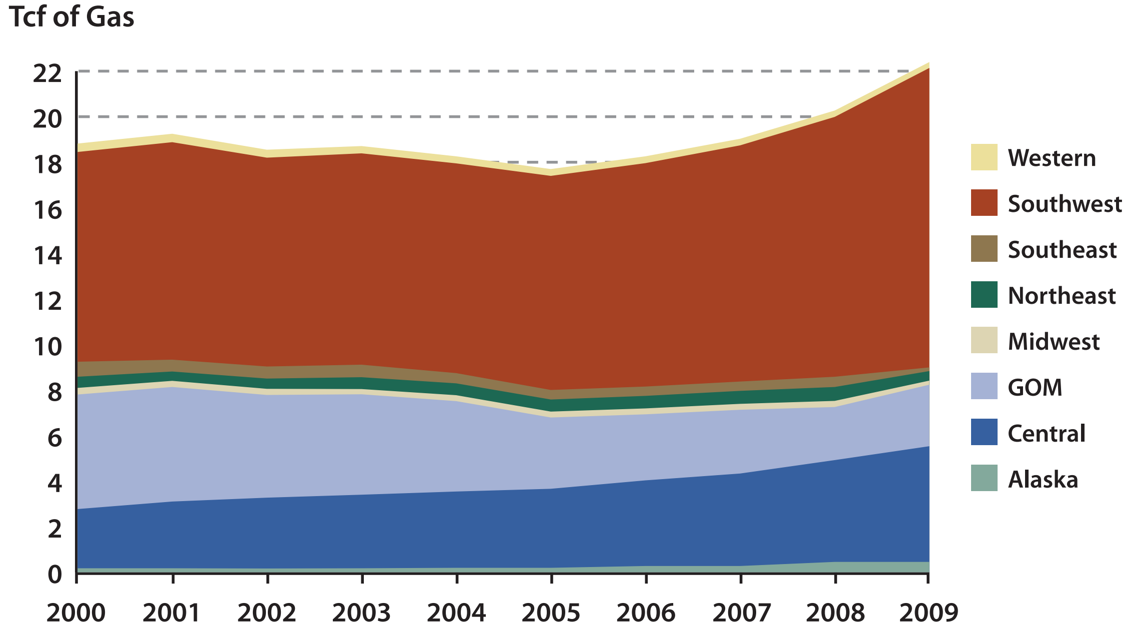
Figure 2.12 illustrates the regional breakdown of dry natural gas production in the U.S. since 2000. Some level of production occurs in all eight regions, but the dominance of the Southwest, Gulf of Mexico, and Central regions is clearly shown. The dynamics of the production levels across these major regions have differed appreciably over the past decade. In the Southwest, the largest gas producing region, annual production levels remained relatively flat at about 9.3 Tcf from 2000 to 2005. Since 2005, output from the region has increased, growing by 21% to 11.4 Tcf in 2008. Much of this growth in the latter half of the decade is the result of rapid expansion in the production of gas from shale plays.

**Figure 2.11 EIA Natural Gas Pipeline Regions for the L48 States; the State of Alaska and the U.S. Offshore Territory in the Gulf of Mexico Form Two Additional Regions**




Source: U.S. Energy Information Administration

**Figure 2.12 Regional Breakdown of Annual Dry Gas Production in the U.S. between 2000 and 2009**




Source: MIT; U.S. Energy Information Administration

Since 2000, the Central region has seen the greatest percentage growth in production among U.S. regions. Annual dry gas output has risen from 2.6 Tcf to 4.5 Tcf, an overall increase of 75%. Unlike the Southwest region, production from the Central region has grown continuously since 2000, with output increasing from all resource types. In marked contrast, gas output from offshore fields in the Gulf of Mexico has fallen dramatically from approximately 5 Tcf in 2000 to 2.4 Tcf in 2008, the result of fewer new wells being brought online in the Gulf to replace those older wells that are now in decline or have been taken off production. This decline is an indication of the maturity of the conventional resource base in the Gulf of Mexico.

## PRODUCTION TRENDS BY RESOURCE TYPE IN THE UNITED STATES

In a global context, U.S. gas production by type is extremely diverse. Both conventional and unconventional gas output is significant, with the contribution of unconventional gas growing steadily year-on-year.

Figure 2.13a plots contributions to production from conventional, unconventional, and associated gas. This breakdown illustrates the marked shift towards unconventional resources that has been a feature of gas production in the U.S. over the past decade and more. In 2000, the combined gross production of conventional and associated gas in the L48 states was 14.6 Tcf (71% of total output). By 2009, the combined conventional and associated output had fallen to 11.4 Tcf (52% of the total). In concert with this fall in conventional and associated gas production, there has been continuous expansion in the production of unconventional gas, with approximately 4.5 Tcf more unconventional gas being produced in 2009 than in 2000.

**Figure 2.13a Breakdown by Type of Annual Gross Gas Production in the L48 U.S. between 2000 and 2009**

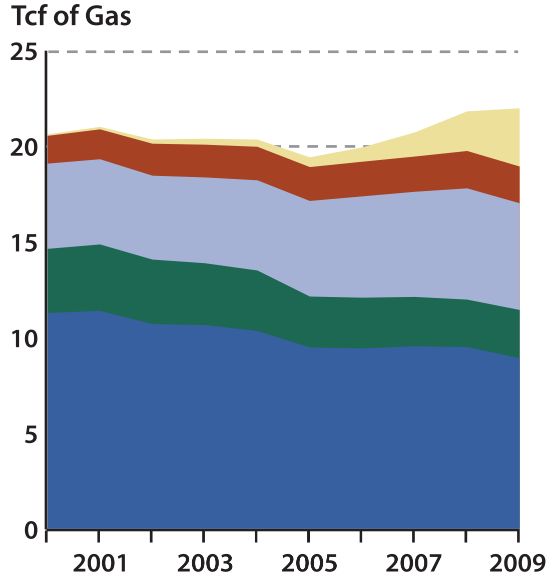
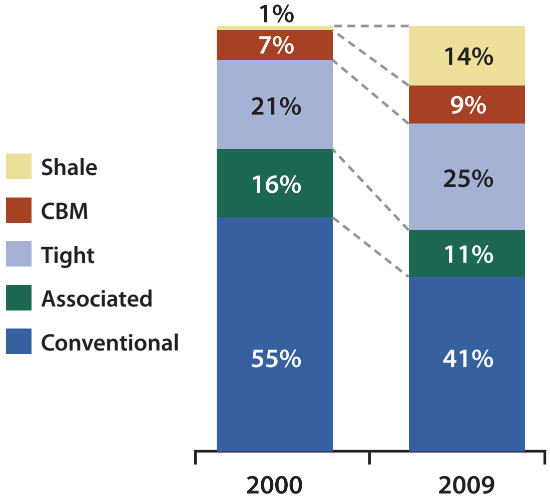



**Figure 2.13b Percentage Breakdown by Type of Gross Gas Production in the L48 U.S. in 2000 and 2009**




Source: MIT; HPDI production database

Historically, tight gas has been the most significant source of unconventional gas production in the U.S., and is likely to remain so for some time. Tracking tight gas production can be difficult because it can exist in a continuum with conventional gas. However, a review of output from known tight plays shows a growth in annual output from 4.5 Tcf to 5.6 Tcf between 2000 and 2009, an increase from 21% to 25% of total gross production as shown in Figure 2.13b. Commercial production of CBM began at the end of the 1980s, and grew substantially during the 1990s from an output of 0.2 Tcf in 1990 to 1.3 Tcf in 1999. This growth moderated during the last decade, with 2009 CBM output standing at 1.92 Tcf or 9% of the total.

Aside from the fall in conventional production, the most striking feature of the gas production in the U.S. this past decade has been the emergence of shale gas. Although shale resources have been produced in the U.S. since 1821, the volumes have not been significant. This situation changed fundamentally during the past decade as technological advances enabled production from shales previously considered uneconomical. Expansion in shale gas output is illustrated in Figures 2.13a and 2.13b. From 2000 to 2009, the contribution of shale gas to overall production grew from 0.1 Tcf, or less than 1%, to 3.0 Tcf, or nearly 14%. This growth is all the more remarkable in that 80% of it was driven by one play, the Barnett shale, located in Texas' Fort Worth Basin. Activity in other shale plays has also been increasing, with appreciable volumes now being produced from the Fayetteville and Woodford shales in the Arkoma Basin, the Haynesville shale in the East Texas Basin, and as of the end of 2009, the Marcellus shale in the Appalachian Basin.

## U.S. RESOURCES[12]

Table 2.1 illustrates mean U.S. resource estimates from a variety of resource assessment authorities. These numbers have tended to grow over time, particularly as the true potential of the unconventional resource base has started to emerge over the past few years.

For this study, we have assumed a mean remaining resource base of around 2,100 Tcf. This corresponds to approximately 92 times the annual U.S. consumption of 22.8 Tcf in 2009. We estimate the low case (with a 90% probability of being met or exceeded) at 1,500 Tcf, and the high case (with a 10% probability of being met or exceeded) at 2,850 Tcf.

Around 15% of the U.S. resource is in Alaska, and full development of this resource will require major pipeline construction to bring the gas to market in the L48 states. Given the abundance of L48 supplies, development of the pipeline is likely to be deferred yet again, but this gas represents an important resource for the future.

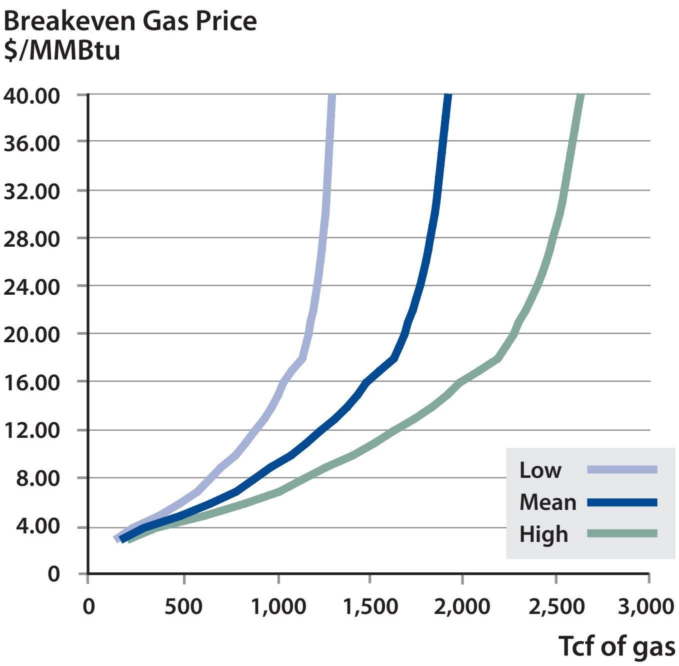
In the L48, some 55% to 60% of the resource base is conventional gas, both onshore and offshore. Although mature, the conventional resource base still has considerable potential. Around 60% of this resource is comprised of proved reserves and reserve growth, with the remainder — of the order of 450 to 500 Tcf — from expected future discoveries.

**Table 2.1 Tabulation of U.S. Resource Estimates by Type, from Different Sources**

<table>
<tr><th></th><th>NPC</th><th>USGS/MMS</th><th colspan="2">PGC</th><th>ICF</th></tr>
<tr><th></th><th>(2003)</th><th>(Various Years)</th><th>(2006)</th><th>(2008)</th><th>(2009)</th></tr>
<tr><td>L48</td><td></td><td></td><td></td><td></td><td></td></tr>
<tr><td>Conventional</td><td>691</td><td>928</td><td rowspan="3">966</td><td rowspan="2">869</td><td>693</td></tr>
<tr><td>Tight</td><td>175</td><td>190</td><td>174</td></tr>
<tr><td>Shale</td><td>35</td><td>85</td><td>616</td><td>631</td></tr>
<tr><td>CBM</td><td>58</td><td>71</td><td>108</td><td>99</td><td>65</td></tr>
<tr><td>Total L48</td><td>959</td><td>1,274</td><td>1,074</td><td>1,584</td><td>1,563</td></tr>
<tr><td>Alaska</td><td></td><td></td><td></td><td></td><td></td></tr>
<tr><td>Conventional</td><td>237</td><td>357</td><td rowspan="3">194</td><td rowspan="2">194</td><td rowspan="2">237</td></tr>
<tr><td>Tight</td><td>–</td><td>–</td></tr>
<tr><td>Shale</td><td>–</td><td>–</td><td>–</td><td>–</td></tr>
<tr><td>CBM</td><td>57</td><td>18</td><td>57</td><td>57</td><td>57</td></tr>
<tr><td>Total Alaska</td><td>294</td><td>375</td><td>251</td><td>251</td><td>294</td></tr>
<tr><td>U.S.</td><td></td><td></td><td></td><td></td><td></td></tr>
<tr><td>Conventional</td><td>929</td><td>1,284</td><td rowspan="3">1,160</td><td rowspan="2">1,063</td><td>930</td></tr>
<tr><td>Tight</td><td>175</td><td>190</td><td>174</td></tr>
<tr><td>Shale</td><td>35</td><td>85</td><td>616</td><td>631</td></tr>
<tr><td>CBM</td><td>115</td><td>89</td><td>165</td><td>156</td><td>122</td></tr>
<tr><td>Total U.S.</td><td>1,254</td><td>1,648</td><td>1,325</td><td>1,835</td><td>1,857</td></tr>
<tr><td>Proved Reserves</td><td>184</td><td>245</td><td>204</td><td>245</td><td>245</td></tr>
<tr><td>Total (Tcf)</td><td>1,438</td><td>1,893</td><td>1,529</td><td>2,080</td><td>2,102</td></tr>
</table>

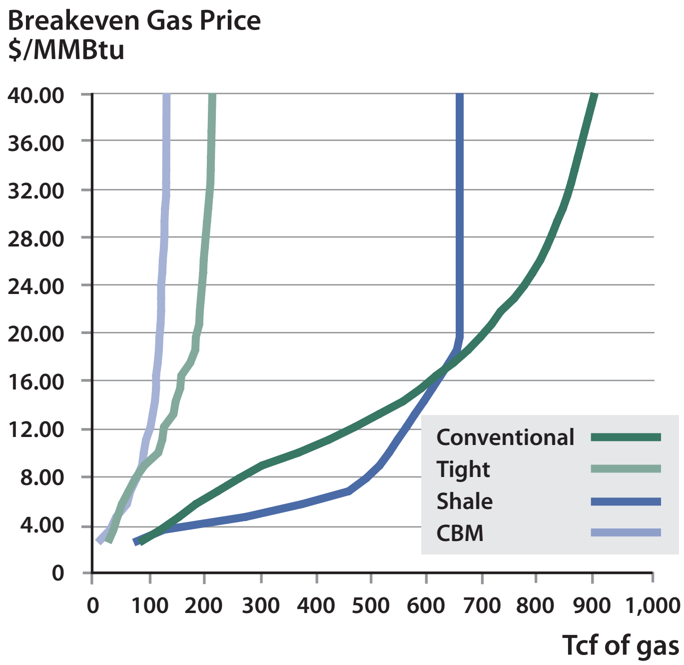
Source: National Petroleum Council 2003; United States Geological Survey 2010; Minerals Management Service 2006; Potential Gas Committee 2007; Potential Gas Committee 2009; Energy Information Administration 2009

**Figure 2.14a Volumetric Uncertainty of U.S. Gas Supply Curves; 2007 Cost Base**




Source: MIT; ICF North American Hydrocarbon Supply Model

**Figure 2.14b Breakdown of Mean U.S. Gas Supply Curve by Type; 2007 Cost Base**




Source: MIT; ICF North American Hydrocarbon Supply Model

Figure 2.14a represents the supply curves for the aggregate of all U.S. resources, depicting the mean estimate and the considerable range of uncertainty. Figure 2.14b illustrates the mean supply curves, broken down by resource type. It clearly shows the large remaining conventional resource base, although it is mature and some of it will require high gas prices to become economical to develop. These curves assume current technology. In practice, future technology development will enable these costs to be driven down over time, allowing a larger portion of the resource base to be economically developed.

Figure 2.14b also demonstrates the considerable potential of shale supplies. Using a 2007 cost base, a substantial portion of the estimated shale resource base is economic at prices between $4/MMBtu and $8/MMBtu. As we see in the current U.S. gas markets, some of the shale resources will displace higher-cost conventional gas in the short to medium term, exerting downward pressure on gas prices.

Despite the relative maturity of the U.S. gas supply, estimates of remaining resources have continued to grow over time — with an accelerating trend in recent years, mainly attributable to unconventional gas, especially in the shales.

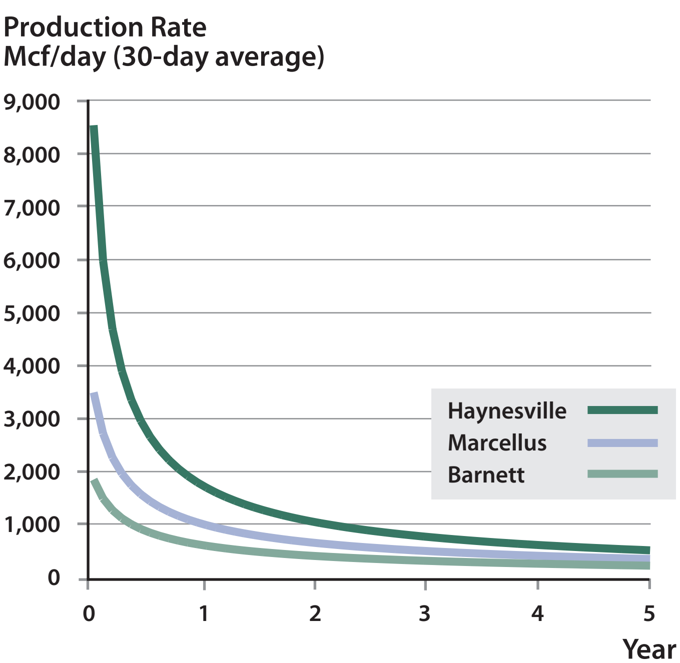
The Potential Gas Committee (PGC), which evaluates the U.S. gas resource on a biannual cycle, provides perhaps the best historical basis for looking at resource growth over time. According to this data, remaining resources have grown by 77% since 1990, despite a cumulative production volume during that time of 355 Tcf.

As a subset of this growth process, the application of horizontal drilling and hydraulic fracturing technology to the shales has caused resource estimates to grow over a five-year period from a relatively minor 35 Tcf (NPC, 2003), to a current estimate of 615 Tcf (PGC, 2008), with a range of 420 to 870 Tcf. This resource growth is a testament to the power of technology application in the development of resources, and also provides an illustration of the large uncertainty inherent in all resource estimates.

*According to Potential Gas Committee data, U.S. natural gas remaining resources have grown by 77% since 1990, a testament to the power of technology, and an illustration of the large uncertainty inherent in all resource estimates.*

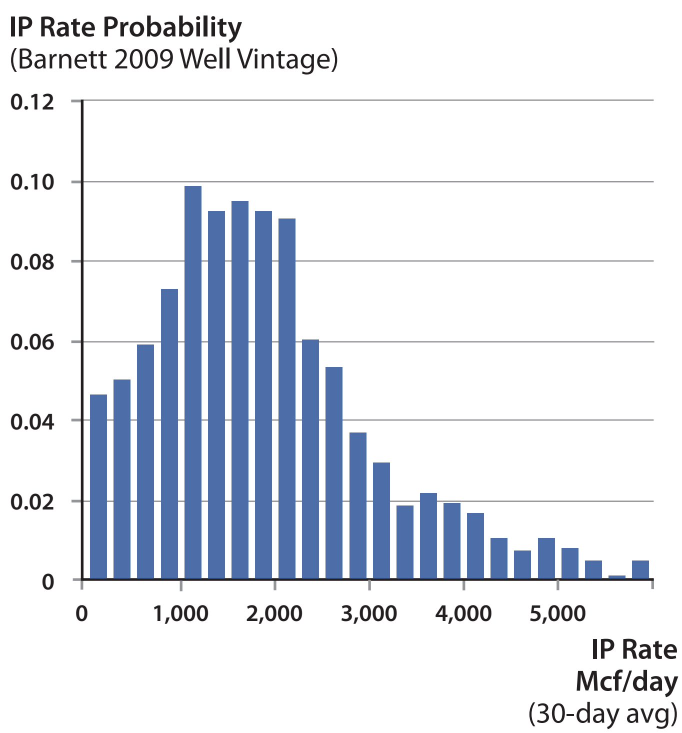
The new shale plays represent a major contribution to the resource base of the U.S. However, it is important to note that there is considerable variability in the quality of the resources, both within and between shale plays. This variability in performance is incorporated in the supply curves on the previous page, as well as in Figure 2.15. Figure 2.15a shows initial production and decline data from three major U.S. shale plays, illustrating the substantial differences in average well performance between the plays. Figure 2.15b shows a probability distribution of initial flow rates from the Barnett formation. While many refer to shale development as more of a "manufacturing process," where wells are drilled on a statistical basis — in contrast to a conventional exploration, development, and production process, where each prospective well is evaluated on an individual basis — this "manufacturing" still occurs within the context of a highly variable subsurface environment.

**Figure 2.15a Illustration of Variation in Mean Production Rates between Three Shale Plays**




Source: MIT analysis; HPDI production database and various industry sources

**Figure 2.15b Illustration of Variation in Initial Production Rates of 2009 Vintage Barnett Wells**




Source: MIT analysis; HPDI production database and various industry sources

This high level of variability in individual well productivity clearly has consequences with respect to the variability of individual well economic performance.[13] This is illustrated in Table 2.2, which shows the variation in breakeven gas price as a function of initial productivity for the five major U.S. shale plays. The P20 30-day initial production rate represents the rate that is equaled or exceeded by only 20% of the wells completed in 2009; the P80 represents the initial rate equaled or exceeded by 80% of completed wells.

Another major driver of shale economics is the amount of hydrocarbon liquid produced along with gas. The results in Table 2.2 assume dry gas with no liquid co-production; however, some areas contain wet gas with appreciable amounts of liquid, which can have a considerable effect on the breakeven economics — particularly if the price of oil is high compared to the price of gas.

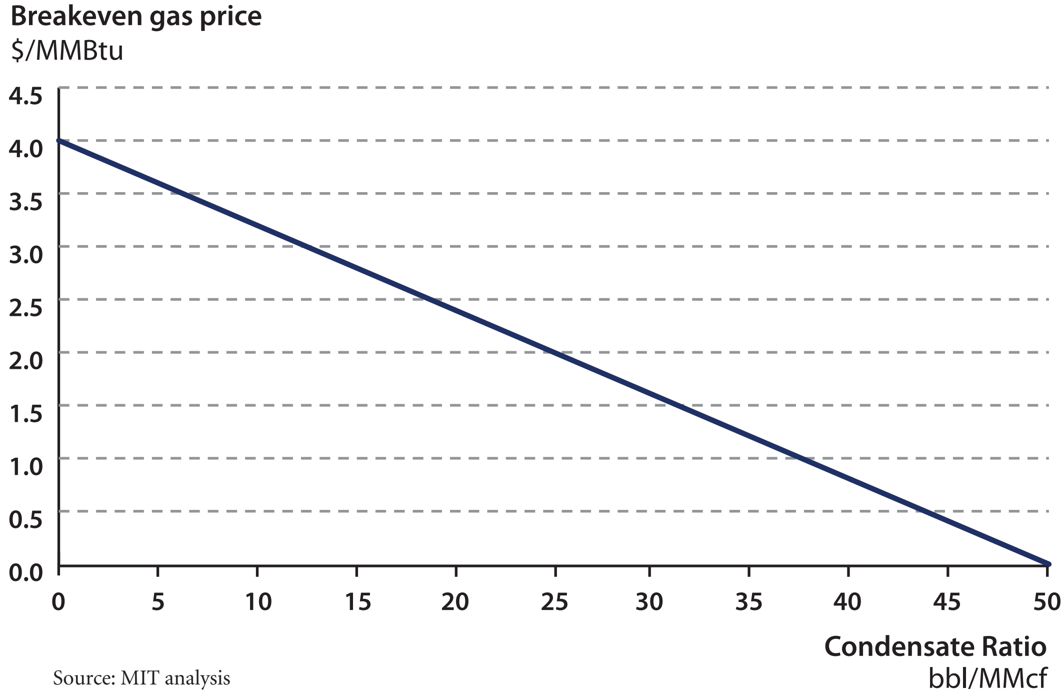
The liquid content of a gas is often measured in terms of the "condensate ratio," expressed in terms of barrels of liquid per million cubic feet of gas (bbls/MMcf). Figure 2.16 shows the change in breakeven gas price for varying condensate ratios in a typical Marcellus well,[14] assuming a liquids price of $80/bbl. It can be seen that for a condensate ratio in excess of approximately 50 bbls/MMcf in this particular case, the liquid production alone can provide an adequate return on the investment, even if the gas were to realize no market value.

**Table 2.2 Full-Cycle 2009 Well Vintage P20, P50, and P80 30-Day Average Initial Production (IP) Rates and Breakeven Prices (BEP) for Each of the Major U.S. Shale Plays Assuming Mid Case Costs**

| | Barnett | | Fayetteville | | Haynesville | | Marcellus | | Woodford | |
|---|---|---|---|---|---|---|---|---|---|---|
| | IP Mcf/d | BEP $/Mcf | IP Mcf/d | BEP $/Mcf | IP Mcf/d | BEP $/Mcf | IP Mcf/d | BEP $/Mcf | IP Mcf/d | BEP $/Mcf |
| P20 | 2700 | $4.27 | 3090 | $3.85 | 12630 | $3.49 | 5500 | $2.88 | 3920 | $4.12 |
| P50 | 1610 | $6.53 | 1960 | $5.53 | 7730 | $5.12 | 3500 | $4.02 | 2340 | $6.34 |
| P80 | 860 | $11.46 | 1140 | $8.87 | 2600 | $13.42 | 2000 | $6.31 | 790 | $17.04 |

Source: MIT analysis

**Figure 2.16 Estimated Breakeven Gas Price ($/MMBtu) for a Mean Performing 2009 Vintage Marcellus Shale Well, with Varying Condensate Ratio (bbl/MMcf), Assuming a Liquids Price of $80/bbl**




Source: MIT analysis

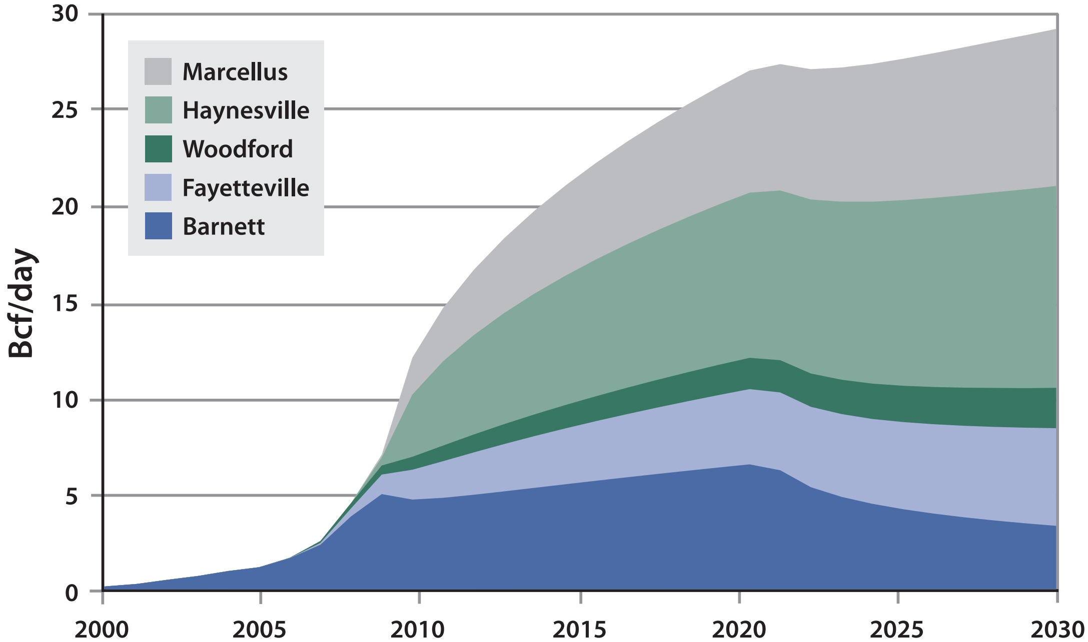
The effects described above create an interesting dynamic in U.S. gas supply. Gas prices had been driven to low levels in 2009 and 2010, at least in part as a result of the abundance of relatively low-cost shale gas. Meanwhile oil prices, determined by global market forces, have remained high. This has led producers to seek liquid rich gas plays, such as certain areas of the Marcellus or the Eagle Ford play in Texas, where condensate ratios can be well in excess of 100 bbl/MMcf. These plays then enable more gas production, even at low gas prices, thus putting further downward pressure on gas prices.

In addition to understanding the resource volumes, it is important to understand the contribution that the new shale resources could make to the overall production capacity within the U.S.

Figure 2.17 indicates how production from the top five shale plays might grow, if drilling were to continue at 2010 levels for the next 20 years. This illustrates the very significant production potential of the shale resource.[15] The current rapid growth in shale production can continue for some time — but in the longer run, production growth tapers off as high initial production rates are offset by high initial decline rates, and the quality of drilling prospects declines as the plays mature.

The large inventory of undrilled shale acreage, together with the relatively high initial productivity of many shale wells, allows a rapid production response to any particular drilling effort, provided that all wells can be completed and tied in. However, this responsiveness will change over time as the plays mature, and significant drilling effort is required just to maintain stable production against relatively high inherent production decline rates.

**Figure 2.17 Potential Production Rate that Could Be Delivered by the Major U.S. Shale Plays up to 2030 – Given 2010 Drilling Rates and Mean Resource Estimates**




Source: MIT analysis

## UNCONVENTIONAL GAS SCIENCE AND TECHNOLOGY[16]

Each unconventional gas resource type — tight gas, CBM, and shale — presents it own production challenges, although they also share some common characteristics. In particular, all three types have low intrinsic permeability within the rock matrix itself — and thus require enhancement of the connectivity between the reservoir and the wellbore to enable gas flow at commercial rates. A second common characteristic is that the resources tend to be distributed over large geographical areas, saturating pore space often hundreds of square kilometres in areal extent, rather than within the tightly defined boundaries of conventional gas reservoirs. This means that exploration risk is very low; the challenges lie in achieving commercial production rates.

Shale resources represent a particular challenge, because of their complexity, variety, and lack of long-term performance data. In conventional reservoirs, there is a long history of production from a wide variety of depositional, mineralogical, and geomechanical environments, such that analogues can be developed and statistical predictions about future performance can be developed. This is not yet the case in the shale plays.

Gas shales refer to any very fine-grained rock capable of storing significant amounts of gas. Gas may be present as free gas stored in the natural fracture and macroporosity, adsorbed onto the kerogen[17] and internal surfaces of the pores or dissolved in the kerogen and bitumen. The highly variable definition of gas shales has led to uncertainty in defining controlling factors that constitute an economic development. Values of the key parameters used in identifying potential shale resources vary widely between shale plays, making it difficult to apply analogues and expand shale gas exploration and development outside established basins.

Production in shales is a multi-scale and multi-mechanism process. Fractures provide the permeability for gas to flow, but contribute little to the overall gas storage capacity. The porosity of the matrix provides most of the storage capacity, but the matrix has very low permeability. Gas flow in the fractures occurs in a different flow regime than gas flow in the matrix. Because of these differing flow regimes, the modeling of production performance in fractured shale formations is far more complex than for conventional reservoirs, and scaling modeling results up to the field level is very challenging. This in turn makes it difficult to confidently predict production performance and devise optimal depletion strategies for shale resources.

Production behavior in shale wells is marked by a rapid decline from initial production rates, as seen in Figure 2.15a. Early gas production is dominated by free gas depleted from the fractures and the macroporosity. This rapid initial decline is followed by a long-term, much slower decline. As the pressure is lowered, gas desorbs from the organic matter in the matrix and diffuses into the fracture system. During this stage, desorption and diffusion through the matrix drive production. The long-term production behavior of a shale gas well is dependent on the time scale of flow from the matrix relative to flow in the fracture network.

In addition to the complexities of modelling performance, core analysis techniques developed for conventional gas, CBM, and tight gas do not work well in shale reservoirs, because they implicitly assume that the same production mechanisms are applicable. The determination of initial parameters such as permeability, porosity, and initial gas-in-place can be misleading, contributing to uncertainty in resource size and production performance.

In order to ensure the optimal development of these important national assets, it is necessary to build a comprehensive understanding of geochemistry, geological history, multiphase flow characteristics, fracture properties, and production behavior across a variety of shale plays. It is also important to develop tools that can enable the scaling up of pore-level physics to reservoir-scale performance prediction, and make efforts to improve core analysis techniques to allow accurate determination of the recoverable resource.

**RECOMMENDATION**

**The U.S. Department of Energy (DOE) should sponsor additional Research and Development (R&D), in collaboration with industry and academia, to address some of the fundamental challenges of shale gas science and technology, with the goal of ensuring that this national resource is exploited in the optimal manner.**

### Resource assessment

It is in the national interest to have the best possible understanding of the size of the U.S. natural gas resource. For conventional reservoirs, statistically based resource assessment methodologies have been developed and tested over many years. In contrast, the assessment methodology for the "continuous" unconventional resources is less well developed. There would be real benefit in improving the methodology for unconventional resource assessments.

**RECOMMENDATION**

**The USGS should continue, and even accelerate, its efforts to develop improved assessment methodologies for unconventional resources.**

### Technology

The development of unconventional resources in general, and shale resources in particular, has been enabled by the application of existing technology — horizontal drilling and hydraulic fracturing — in a new setting. The objective is to create very large surface areas in the formation that are in communication with the wellbore. Horizontal wells place 4,000 feet or more of well directly into the formation, while multistage fracturing along the horizontal section then creates additional surface area in communication with the wellbore.

Improvements in drilling and fracturing performance are currently rapid, coming from improved know-how rather than specific technology breakthroughs. The repetitive nature of the shale drilling and completion process provides an ideal environment for continuous improvement of drilling and completion times, and fracturing performance. These improvements can serve to enhance well economics and increase the ultimate resource base.

There are a number of areas of technology development that could enhance unconventional gas recovery in the longer term:

- Drilling — unconventional resources require a high well density for full development. Technology that can reduce well costs and increase wellbore contact with the reservoir can make a significant impact on costs, production rates, and ultimate recovery. Multi-lateral drilling, whereby a number of horizontal sections can be created from a single vertical wellbore, and coiled tubing drilling to decrease costs represent potential options for future unconventional gas development.

- $CO_2$ enhanced recovery — simultaneous recovery of natural gas while sequestering $CO_2$ provides an interesting, although as yet unproven, possibility for enhancing gas recovery while reducing environmental footprint. In enhanced CBM production, $CO_2$ injected into the reservoir preferentially displaces methane molecules, allowing for enhanced gas production while storing $CO_2$ permanently in the subsurface. While pilot projects have successfully demonstrated enhanced recovery from this technique, there are significant challenges associated with making this a commercial-scale process.

- Seismic techniques — micro-seismic techniques are now commonly used to estimate the length and orientation of induced fractures in the reservoir during fracturing operations; this technique is useful for improving fracturing effectiveness. At a more macroscopic level, there is a need to develop seismic techniques that allow the characterisation of large areas, to identify formation "sweet spots," natural fracture orientation, and other properties that would be invaluable in improving overall resource development.

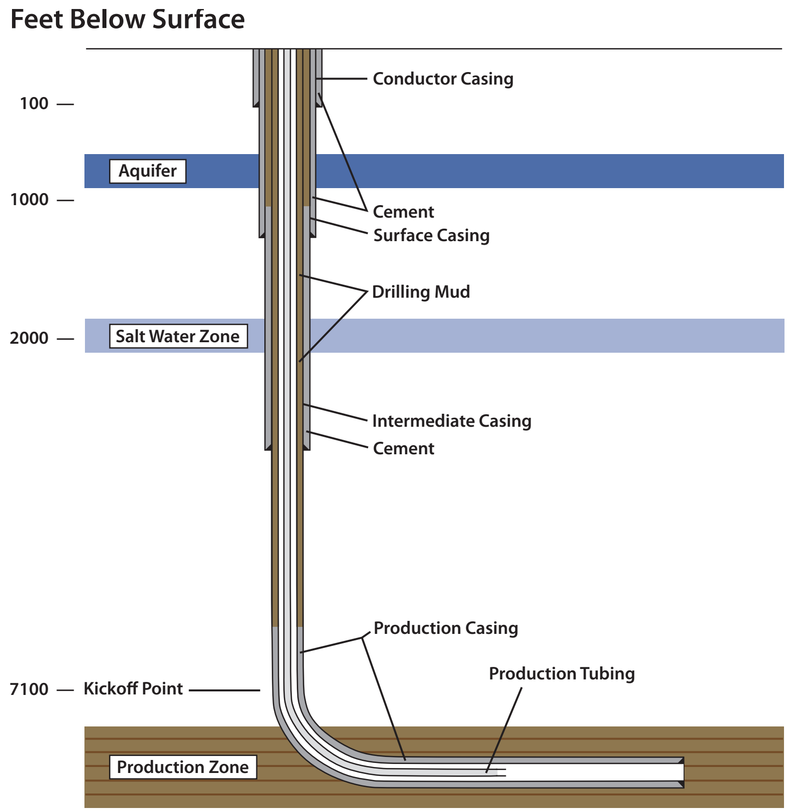
## SHALE GAS ENVIRONMENTAL CONCERNS

### Background

The rapid development of shale gas resources in the U.S. over the past few years has aroused concern, and a perception in some quarters that this development is causing significant environmental problems. A good deal of attention has been focused on the high-volume hydraulic fracturing that is an essential component of shale gas development, with a major concern being that the fracturing process risks injecting toxic fracture fluids into shallow groundwater aquifers, which are in many cases the source of potable water for public use. More broadly, there are concerns about water management and in particular the proper disposal of potentially toxic wastewater from the fracturing procedure.

These concerns have led to restrictions on drilling in some areas and proposed regulatory action. Activity is currently restricted in potentially productive areas of the Marcellus shale in the Delaware River Basin, New York State and Pennsylvania State Forest land. The U.S.

**Figure 2.18 Typical Shale Well Construction** (Not to Scale)




Source: Based on Modern Shale Gas Development in the United States – a Primer

Environmental Protection Agency (EPA) is conducting an extensive review of hydraulic fracturing, and legislation in the form of the Fracturing Responsibility and Awareness of Chemicals (FRAC) Act was introduced in the 2009–2010 Congress.[18]

## The Shale Drilling and Completion Process

In order to appreciate the risks associated with shale development, and to understand appropriate risk mitigation techniques, it is helpful to understand the major steps involved in well construction:

1. Well permitting — states require an operator to obtain a permit to drill a well.

2. Well site construction — typically involves cleaning and grading an area of around four acres in the case of a single well site, or five to six acres in the case of a multi-well site.

3. Drilling and casing — as shown in Figure 2.18, casing is cemented into the well at various stages in order to maintain the integrity of the wellbore, and to ensure that fluids within the various strata are contained within those strata. The drilling and casing process usually entails several stages:

   (i) Drill and set conductor casing — large diameter casing set at shallow depths.

   (ii) Drill through shallow freshwater zones, set and cement surface casing — the most critical phase with respect to the protection of groundwater resources.

   (iii) Drill and cement intermediate casing.

   (iv) Drill and cement production casing.

4. Perforate and fracture the well, usually in multiple stages.

5. Flowback fracture fluid.

6. Place well into production.

### Potential Risks

With over 20,000 shale wells drilled in the last 10 years, the environmental record of shale gas development has for the most part been a good one. Nevertheless, it is important to recognize the inherent risks of the oil and gas business and the damage that can be caused by just one poor operation; the industry must continuously strive to mitigate risk and address public concerns. Particular attention should be paid to those areas of the country which are not accustomed to oil and gas development, and where all relevant infrastructure, both physical and regulatory, may not yet be in place. In this context, the Marcellus shale, which represents 35% to 40% of the U.S. shale resource, is the primary concern.

Within the stages of well construction outlined above, the primary risks are as follows:

1. Contamination of groundwater aquifers with drilling fluids or natural gas while drilling and setting casing through the shallow zones.

2. On-site surface spills of drilling fluids, fracture fluids, and wastewater from fracture flowbacks.

3. Contamination as a result of inappropriate off-site wastewater disposal.

4. Excessive water withdrawals for use in high-volume fracturing.

5. Excessive road traffic and impact on air quality.

Before examining these risks in more detail, it is instructive to look at data that attempt to summarize available information on recorded incidents relating to gas well drilling in the U.S. L48 onshore. It is beyond the scope of this study to examine multiple state archives to review individual well incident reports. Instead, to provide a high-level view we have extracted and combined the results from a number of reports that have reviewed drilling-related incidents in the U.S. over the past few years. Table 2.3 indicates the results of this analysis, while Appendix 2E provides a fuller description of the data set. The data set does not purport to be comprehensive, but is intended to give a sense of the relative frequency of various types of incidents.

*With over 20,000 shale wells drilled in the last 10 years, the environmental record of shale gas development has for the most part been a good one — but it is important to recognize the inherent risks and the damage that can be caused by just one poor operation.*

**Table 2.3 Widely Reported Incidents Involving Gas Well Drilling; 2005–2009**

| Type of Incident | Number Reported | Fraction of Total |
|---|---|---|
| Groundwater contamination by natural gas or drilling fluid | 20 | 47% |
| On-site surface spills | 14 | 33% |
| Off-site disposal issues | 4 | 9% |
| Water withdrawal issues | 2 | 4% |
| Air quality | 1 | 2% |
| Blowouts | 2 | 4% |

Of the 43 widely reported incidents, almost half appear to be related to the contamination of shallow water zones primarily with natural gas. Another third of reported incidents pertain to on-site surface spills. In the studies surveyed, no incidents are reported which conclusively demonstrate contamination of shallow water zones with fracture fluids.

### The Fracturing Process

The fracturing process entails the pumping of fracture fluids, primarily water with sand proppant and chemical additives, at sufficiently high pressure to overcome the compressive stresses within the shale formation for the duration of the fracturing procedure. Each stage is typically of the order of a few hours. The process increases formation pressure above the critical fracture pressure, creating narrow fractures in the shale formation. The sand proppant is then pumped into these fractures to maintain a permeable pathway for fluid flow after the fracture fluid is withdrawn and the operation is completed.

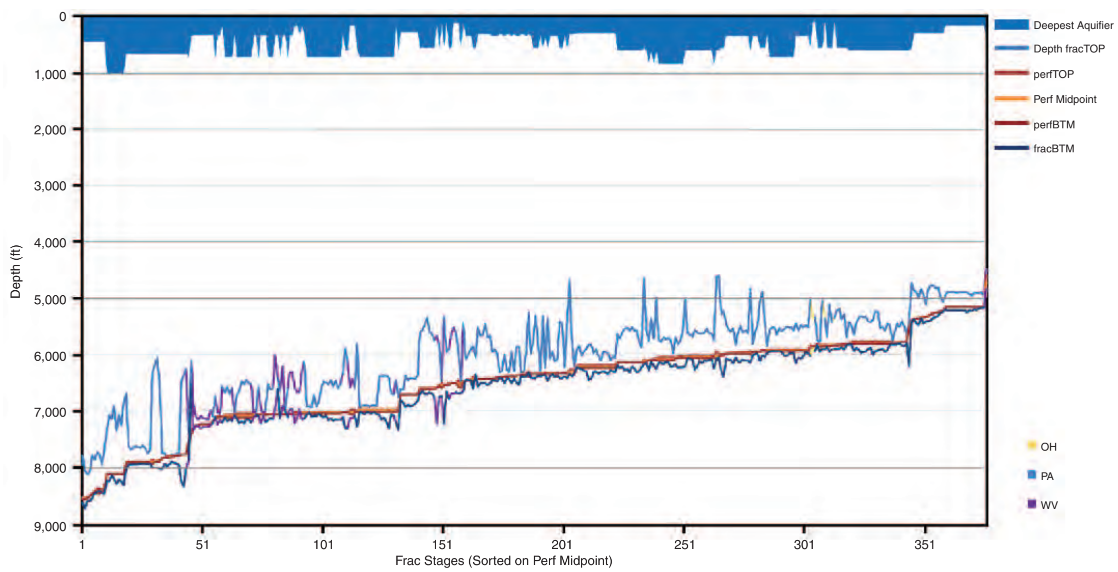
The fracturing process itself poses minimal risk to the shallow groundwater zones that may exist in the upper portion of the wellbore. As described previously, multiple layers of cement and casing protect the freshwater zones as the fracture fluid is pumped from the surface down into the shale formation. This protection is tested at high pressures before the fracturing fluids are pumped downhole. Once the fracturing process is underway, the large vertical separation between the shale sections being fractured and the shallow zones prevents the growth of fractures from the shale formation into shallow groundwater zones. Table 2.4 describes the typical separations in the major shale plays; in all but one case there are several thousand feet of rock — typically sandstones and shales, many of which have very low permeability — separating the fractures shale formation and the groundwater zones. It should be noted here that only shallow zones contain potable water; as depths increase, the salinity of the groundwater increases to the point that it has no practical utility.

A recently published report summarizes the results of a large number of fracturing operations in the Barnett and the Marcellus shales (Fisher, 2010). Figure 2.19 illustrates these results for the Marcellus shale, showing that in all cases the highest growth of the fractures remains separated from the groundwater aquifers by thousands of feet of formation.

**Table 2.4 Separation Distance between Gas Shales and Shallow Freshwater Aquifers in Major Plays**

| Basin | Depth to Shale (ft) | Depth to Aquifer (ft) |
|---|---|---|
| Barnett | 6,500–8,500 | 1,200 |
| Fayetteville | 1,000–7,000 | 500 |
| Marcellus | 4,000–8,500 | 850 |
| Woodford | 6,000–11,000 | 400 |
| Haynesville | 10,500–13,500 | 400 |

**Figure 2.19 Fracture Growth in the Marcellus; Marcellus Shale Mapped Fracture Treatments (Total Vertical Depth (TVD))**




Source: Pinnacle Halliburton Service, Kevin Fisher, Data Confirm Safety of Well Fracturing from July 2010

The physical realities of the fracturing process, combined with the lack of reports from the many wells to date of fracture fluid contamination of groundwater, supports the assertion that fracturing itself does not create environmental concerns. However, this simple statement does not address the full range of environmental concerns listed earlier:

1. **Leakage of natural gas or drilling fluids into shallow zones:** this appears to be the most common cause of reported incidents, and it is generally associated with drilling and setting the surface casing. There are three potential risks during this phase of operation: (1) overweight drilling mud causing some drilling fluid leakage into groundwater zones; (2) unexpected encounters with shallow gas zones with the possibility of gas migration into groundwater zones; and (3) poor quality cementing of the surface casing, allowing a potential fluid pathway into the groundwater zones during subsequent operations. The protection of groundwater aquifers is one of the primary objectives of state regulatory programs, and it should be emphasized that good oil field practice, governed by existing regulations, should provide an adequate level of protection from these problems.

   Nevertheless, regulations vary by state, as a function of local conditions and historical precedent — best practice involves setting cement all the way to surface, and conducting pressure tests and cement-bond logs to ensure the integrity of the surface casing. A detailed comparison of state-by-state regulation would facilitate the widespread adoption of best practice.

**RECOMMENDATION**

**Conduct an inter-state regulatory review and, within constraints of local considerations, adopt best practice for drilling and high-volume hydraulic fracturing.**

2. **On-site surface spills:** the drilling and completion process involves the handling of many thousands of barrels of fluids on site, in particular drilling mud and fracture fluids. Spills can occur as a result of failure of equipment such as pumps and hoses; in addition, there is potential for overflow of tanks and surface pits. Issues will arise if the volume of spilled material is such that local waterways could be contaminated. These issues are not specifically associated with the fracturing process, and avoiding spills is a normal part of good oil field management practice. The high volumes of fluid associated with shale fracturing may increase spill potential.

   Again, state regulations stipulate the requirements for protecting surface waters against leaks and spills, with regulation varying from state to state.

   Shale fracture fluid or "slickwater," is largely composed of water, which generally constitutes over 99% of the liquid component. As described in Table 2.5, a number of additives are mixed in with the water to increase the effectiveness of the fracturing operation — these additives will vary as a function of the well type and the preferences of the operators. While there has been concern about the transparency of information as regards the make-up of these additives, there has been considerable progress on this issue. Although precise formulations remain proprietary, information is now becoming available for all the chemical compounds contained within the fluids.

In addition to greater transparency about the compounds, there is also progress towards elimination of the toxic components from the additives.

**RECOMMENDATION**

**Require the complete disclosure of all fracture fluid components.**

**RECOMMENDATION**

**Continue efforts to eliminate toxic components of fracture fluids.**

**Table 2.5 Typical Fracture Fluid Additives**

| Purpose | Chemical | Common Use |
|---|---|---|
| clean up damage from initial drilling, initiate cracks in rock | HCl | swimming pool cleaner |
| gel agents to adjust viscosity | guar gum | thickener in cosmetics, toothpaste, sauces |
| viscosity breakers | ammonium persulfate, potassium, sodium peroxydisulfate | bleach agent in detergent and hair cosmetics |
| biocides | gluteraldehyde, 2,2-dibromo3-nitrilophopionamide | medical disinfectant |
| surfactant | isopropanol | glass cleaner, antiperspirant |
| corrosion inhibitor | n, n-dimethylformamide | pharmaceuticals |
| clay stabilizer | potassium chloride | low-sodium table salt substitute |

Source: Kaufman et al. 2008

3. **Off-site wastewater disposal** — another potential issue is the disposal of waste from fracturing operations, in particular the fracture fluid and formation water that is returned from the well when it is back-flowed upon completion of the fracturing operation, prior to start of production. Typically, less than 100% of the injected fluid will be recovered, and it will generally be mixed with some volume of displaced formation brine. This fluid must be disposed of appropriately.

   Every year the onshore U.S. industry safely disposes of approximately 18 billion barrels of produced water. By comparison, a high-volume shale fracturing operation may return around 50 thousand barrels of fracture fluid and formation water to the surface. The challenge is that these volumes are concentrated in time and space.

   The optimal method for disposal of oil field wastewater is injection into a deep saline aquifer through an EPA regulated Underground Injection Control (UIC) water disposal well. Problems can occasionally arise if there are insufficient wastewater disposal wells, as appears to be the case in Pennsylvania. Waste can be disposed of at wastewater treatment plants, but problems can arise if the fluid for disposal is of high salinity or contains other contaminants[19]; this may cause the effluent from the treatment plant to exceed desired limits.

   Much effort is now focused on addressing this issue where disposal problems exist. One approach is to recycle the flow-back fluid: using the flow-back fluid from one well as a component in the fracture fluid of the next well. This has the additional advantage of reducing the total amount of water that must be imported to site. In addition, techniques are also being developed to clean up wastewater prior to disposal.

4. **Water withdrawal** — large quantities of water, typically of the order of 100,000 barrels, are required for high-volume hydraulic fracturing, and this has raised concerns about the impact on local water resources.

   While there may be temporary impacts on local resources, the overall impact is small, as can be seen when the volumes are placed in the context of total water usage. Table 2.6 looks at water usage for shale gas operations as a fraction of total water usage in a number of major shale plays — in all cases shale development water usage represents less than 1% of total water usage in the affected areas.

**Table 2.6 Comparative Water Usage in Major Shale Plays**

| Play | Public Supply | Industrial/ Mining | Irrigation | Livestock | Shale Gas | Total Water Use (Bbbls/yr) |
|---|---|---|---|---|---|---|
| Barnett TX | 82.7% | 3.7% | 6.3% | 2.3% | 0.4% | 11.1 |
| Fayetteville AR | 2.3% | 33.3% | 62.9% | 0.3% | 0.1% | 31.9 |
| Haynesville LA/TX | 45.9% | 13.5% | 8.5% | 4.0% | 0.8% | 2.1 |
| Marcellus NY/PA/WV | 12.0% | 71.7% | 0.1% | <0.1% | <0.1% | 85.0 |

Source: ALL Consulting

Indeed, the "water intensity" of shale gas development, at around 1 gallon of water consumed for every MMBtu of energy produced, is low compared to many other energy sources. By way of contrast, several thousand gallons of water per MMBtu of energy produced can be used in the irrigation of corn grown for ethanol.

Nevertheless, careful planning and coordination are necessary to ensure that episodic water withdrawals do not disrupt local supply sources.

**RECOMMENDATION**

**Prepare integrated regional water usage and disposal plans for the major shale areas.**

**RECOMMENDATION**

**Undertake collaborative R&D to reduce water usage and develop cost-effective water recycling.**

5. **Road traffic and environmental disturbance** — oil and gas operations have the potential to be disruptive to local communities in the field development phase of well drilling and completion, particularly in those areas not accustomed to routine oil field operations. As indicated in Table 2.7, the large volumes of water involved in fracturing operations can create high volumes of road traffic.

   It should be emphasized that the large number of traffic movements shown on this table are really worst-case numbers. In particular, re-use of flowback wastewater can and does significantly reduce the road traffic associated with hauling water, which represents much of the traffic movement. Furthermore, large-scale operators are also using pipelines to transport water to a site, further reducing the amount of road traffic very substantially.

**Table 2.7 Truck Journeys for a Typical Shale Well Drilling and Completion**

| Activity | 1 Rig, 1 Well | 2 Rigs, 8 Wells |
|---|---|---|
| Pad and Road Construction | 10 – 45 | 10 – 45 |
| Drilling Rig | 30 | 60 |
| Drilling Fluid and Materials | 25 – 50 | 200 – 400 |
| Drilling Equipment (casing, drill pipe, etc.) | 25 –50 | 200 – 400 |
| Completion Rig | 15 | 30 |
| Completion Fluid and Materials | 10 – 20 | 80 – 160 |
| Completion Equipment (pipe, wellhead, etc.) | 5 | 10 |
| Fracturing Equipment (pump trucks, tanks, etc.) | 150 – 200 | 300 – 400 |
| Fracture Water | 400 – 600 | 3,200 – 4,800 |
| Fracture Sand | 20 – 25 | 160 – 200 |
| Flowback Water Disposal | 200 – 300 | 1,600 – 2,400 |
| Total | 890 – 1,340 | 5,850 – 8,905 |

Source: NTC Consulting

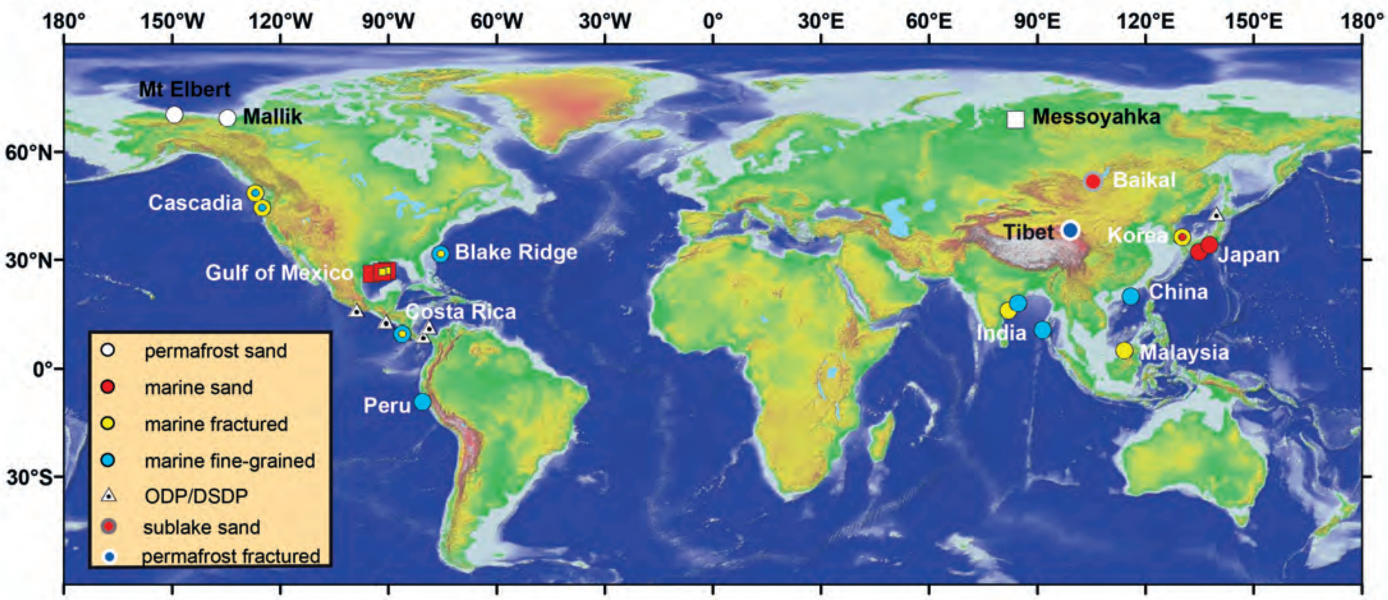
In conclusion, it is clear that oil and gas development is not without risk to the natural environment. State and Federal regulations are designed to mitigate those risks. However, though not the result of risks inherent to the fracturing of shale gas wells, operational errors and poor drilling practice do result in a significant number of incidents. Implementation of the recommendations described above, together with rigorous enforcement of all applicable regulations, should reduce the number of incidents and ensure that shale development can proceed with minimum impact on the environment.

## METHANE HYDRATES[20]

Methane hydrates are not considered in the resource estimates and supply curves described above, as they are still at a very early stage in terms of resource definition and understanding. Nevertheless, gas hydrates could represent a significant long-term resource option, possibly in North America, but particularly in some other parts of the world.

Methane hydrates are an ice-like form of methane and water that are stable at the pressure-temperature conditions common in the shallow sediments of permafrost areas and continental margins. Globally, the total amount of methane sequestered in these deposits probably exceeds 100,000 Tcf, of which ~99% occurs in ocean sediments. Most of this methane is trapped in highly disseminated and/or low saturation methane hydrates that are unlikely to ever be a commercially viable gas source. An estimated 10,000 Tcf may be technically recoverable from high-saturation gas hydrate deposits (Boswell and Collett, 2010), primarily concentrated in permeable (likely sand-rich) sediments.

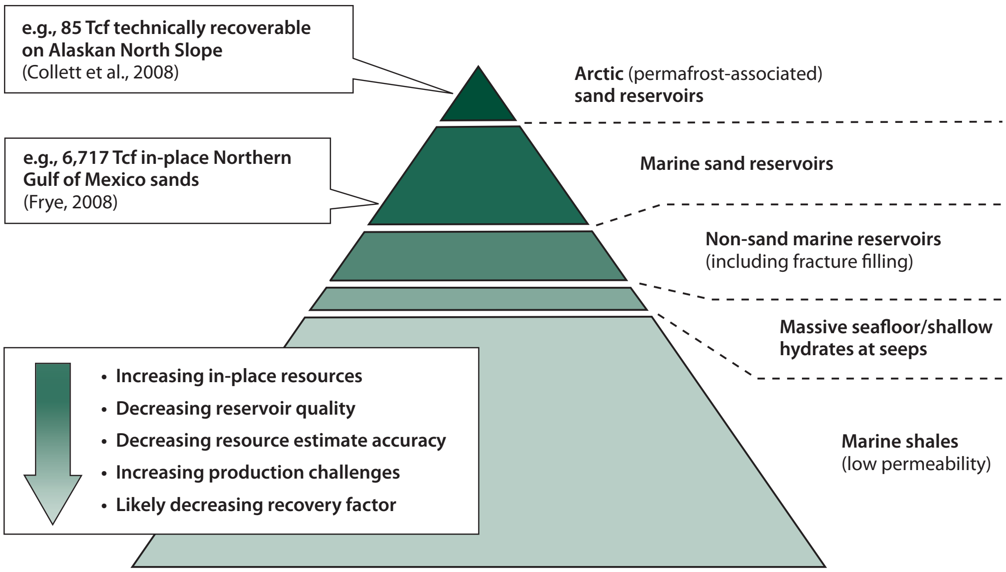
**Figure 2.20 USGS Database of Locations at Which Gas Hydrate Has Been Recovered (circles) or Strongly Inferred Based on Drilling-Based Evidence (squares) from Permafrost Areas (black labels) or from Depths Greater Than 50 m below the Seafloor (white labels). The color-coding refers to the primary (outer symbol) and, where relevant, the secondary (inner symbol) type of gas hydrate reservoir, using terminology from the gas hydrate resource pyramid (Figure 2.21 in MITEI report). Academic drill sites where deep gas hydrate was recovered but for which reservoir type has not been determined are designated by Ocean Drilling Program/Deep Sea Drilling Project (ODP/DSDP).**




Source: Ruppel, C., Collett, T. S., Boswell, R., Lorenson, T., Buczkowski, B., and Waite, W., 2011, A new global gas hydrate drilling map based on reservoir type, Fire in the Ice, DOE-NETL Newsletter, May edition, vol. 11(1), 13–17.

To date, there have been few formal quantitative assessments of methane sequestered in gas hydrates at regional scales. A recent assessment of in-place resources in northern Gulf of Mexico yielded 6,717 Tcf (median) for sands (Frye, 2008), and other assessments based on similar methodology are expected soon for the U.S. Atlantic Margin and other U.S. margins. The only assessment of technically recoverable methane hydrates ever completed calculated 85.4 Tcf (median) for permafrost-associated gas hydrates on the Alaskan North Slope (Collett et al., 2008). Outside the U.S., the only formal assessment covers ~10% of the area associated with a certain gas hydrates seismic marker in the Nankai Trough and yielded 20 Tcf methane in-place in the high saturation section (Fujii et al., 2008).

**Figure 2.21 The Methane Hydrate Resource Pyramid, After Boswell and Collett (2006)**




Source: After Boswell and Collett (2006)

Several research challenges remain before gas hydrate assessments become routine. The greatest need is geophysical methods that can detect gas hydrates and constrain their *in situ* saturations more reliably than seismic surveys alone and less expensively than direct drilling and borehole logging. Electromagnetic (EM) methods have shown some promise in deep marine settings, but refinements in seismic techniques (e.g., full waveform inversions, seismic attribute analysis) may yet prove even more useful than routinely combining EM and seismic surveys.

Methane hydrates are unlikely to reach commercial viability for global markets for at least 15 to 20 years. Through consortia of government, industry, and academic experts, the U.S., Japan, Canada, Korea, India, China, and other countries have made significant progress on locating and sampling methane hydrates. No short-term production test has ever been attempted in a marine gas hydrate setting, but several short-term tests (few hours to a few days) have been completed in permafrost-associated wells in the U.S. and Canadian Arctic. Before 2015, the first research-scale, long-term (several months or longer) production tests could be carried out by the U.S. DOE on the Alaskan North Slope and by the Japanese MH21 project for Nankai Trough deepwater gas hydrates. The goals of these tests are to investigate the optimal mix of production techniques to sustain high rates of gas flow over the lifetime of a well and to assess the environmental impact of production of methane from gas hydrates.

*Methane hydrates are unlikely to reach commercial viability for global markets for at least 15 to 20 years.*

Producing gas from methane hydrates requires perturbing the thermodynamic stability conditions to drive dissociation (breakdown) of the deposits into their constituent gas and water. The gas can then be extracted using well-established production methods. Depressurization of the formation is the preferred technique for driving gas hydrate dissociation since it yields a relatively sustainable and well-controlled flow of gas. Thermal stimulation through direct heating or injection of heated fluids can be used to drive episodic dissociation during longer-term depressurization, but requires significant energy expenditure. Injection of inhibitors (e.g., seawater or some chemicals) can also dissociate gas hydrates in the formation, although this technique has numerous disadvantages and is unlikely to be practical at large scales. A final production method will be tested on the Alaskan North Slope in 2012 by ConocoPhillips and could in theory produce methane as well as sequester $CO_2$: $CO_2$ injected into methane hydrate deposits should liberate methane while simultaneously trapping the $CO_2$ within stable gas hydrates (Yezdimer et al., 2002; Farrell et al., 2010).

At present, most conventional oil and gas producers avoid intersecting gas hydrate deposits to prevent long-term damage to the borehole due to unintended dissociation. Producing gas from methane hydrates will instead require targeted drilling into high-saturation deposits and careful management of potentially large amounts of co-produced water. The depths at which gas hydrate occurs are shallower than those associated with (deepwater) conventional gas, rendering gas hydrate well control less of a challenge. Gas hydrate dissociation is also a self-regulating process in most cases, so there is little danger of runaway dissociation. Changes in bulk sediment volume and sediment strength are expected if high-saturation gas hydrates are dissociated, but the impact of these changes will depend on many factors, including the geologic setting, the depth of the deposits, and the fate of produced water. In short, the risks associated with gas production from methane hydrates located beneath permafrost or deep within marine sediments are either largely known from existing gas operations or considered manageable.

**RECOMMENDATION**

**Continue methane hydrates research program to develop methods for remote detection of highly concentrated deposits; conduct formal resource assessments; and prove the resource potential through long-term production testing.**

## APPENDICES

2A: Additional Data Concerning Natural Gas Resources
2B: Technical Note on Incorporating Supply Volume Sensitivity in Cost Curves
2C: Supply Curve Additional Material
2D: Shale Gas Economic Sensitivities
2E: Overview and Analysis of Publicly Reported Incidents Related to Gas Well Drilling

## SUPPLEMENTARY PAPERS ON MITEI WEBSITE:

SP 2.1 Natural Gas Resource Assessment Methodologies – Dr. Qudsia Ejaz
SP 2.2 Background Material on Natural Gas Resource Assessments, with Major Resource Country Reviews – Dr. Qudsia Ejaz
SP 2.3 Role of Technology in Unconventional Gas Resources – Dr. Carolyn Seto
SP 2.4 Methane Hydrates and the Future of Natural Gas – Dr. Carolyn Ruppel

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Yezdimer, E., Cummings, P., Chalvo, A., 2002. "Extraction of methane from its gas clathrate by carbon dioxide sequestration – determination of the Gibbs Free Energy of gas replacement and molecular simulation." J. Phys. Chem A., 106 p. 7982–7987.

## NOTES

[1]Thermogenic gas is formed by the application of heat and pressure on organic matter; natural gas can also be formed through a biogenic process, in which microbial action in an anaerobic (oxygen free) environment creates methane from organic matter — for example, in swamps, land-fills and shallow formations. This chapter of the report is focused on thermogenic gas.

[2]Permeability is a measure of the ability of a porous medium, such as that found in a hydrocarbon reservoir, to transmit fluids, such as gas, oil or water, in response to a pressure differential across the medium. In petroleum engineering, permeability is usually measured in units of millidarcies (mD). Unconventional formations, by definition, have permeability less than 0.1mD.

[3]ICF International is a consulting firm whose services were used in preparation of supply curves for this study.

[4]In the US, natural gas volumes are typically measured in Standard Cubic Feet (Scf), where the volume is measured at a temperature of 60°F and a pressure of one atmosphere (14.7 pounds per square inch). 1 trillion cubic feet (Tcf) = 1,000,000,000,000 (or $10^{12}$) Scf. Outside North America, natural gas volumes are typically measured in cubic meters. 1 cubic meter ≈ 35.3 cubic feet.

[5]Appendix 2A provides additional maps and detailed data tables concerning gas resource estimates. Supplementary Paper SP 2.2 "Background Material on Natural Gas Resource Assessments with Major Resource Country Reviews," by Dr. Qudsia Ejaz, published on the MITEI website, provides additional material.

[6]Appendix 2B provides details on the methodology used to create the uncertainty estimates shown in this chapter.

[7]Appendix 2C provides further details of cost curves prepared for this study.

[8]Supply curves shown here are based on oil field costs in 2007. There has been considerable oil field cost inflation, and some recent deflation, in the last 10 years. We have estimated cost curves on a 2004 base (the end of a long period of stable costs) and a 2007 base (reasonably comparable to today's costs, 70% higher than the 2004 level, and continuing to decline).

[9]Appendix 2A contains further details on global unconventional resources.

[10]Rogner, "An Assessment of World Hydrocarbon Resources", 1997.

[11]At the time of writing, new more detailed estimates of global unconventional resources are starting to be published. See, for example, *World Shale Gas Resources: An Initial Assessment of 14 Regions Outside the United States*. Produced by Advanced Resources International (ARI) for the U.S. EIA April 2011.

[12]Appendix 2A provides additional maps and detailed data tables concerning gas resource estimates.

[13]Appendix 2D contains a detailed discussion of the economic performance of the major U.S. shale plays.

[14]These are illustrative calculations only, not based on actual "wet" well performance. The calculations assume that well performance, costs, etc., are unchanged by increasing levels of liquids production. In practice, gas production may be affected by liquid co-production.

[15]This is not a forecast of production — but rather an illustration of the production potential at an assumed drilling rate and assuming a median estimate of resources.

[16]A detailed discussion of the science and technology of unconventional gas resources can be found in the Supplementary Paper SP 2.3 "Role of Technology in Unconventional Gas Resources," by Dr. Carolyn Seto, published on the MITEI website.

[17]Kerogen and bitumen are comprised of organic matter that occurs in hydrocarbon source rocks, formed from the application of heat and pressure to buried organic material over geological time. Kerogen is insoluble in normal organic solvents, while bitumen is soluble.

[18]The Fracture Responsibility and Awareness of Chemicals (FRAC) Act of 2009 proposed to regulate fracturing under the Underground Injection Control provisions of the Safe Water Drinking Act, and to mandate full disclosure of the chemical constituents of all fracture fluid additives. The Bill did not make it out of Committee during the 2009–2010 session of Congress.

[19]Flowback fluid can contain: dissolved solids (chlorides, sulfates, and calcium); metals (calcium, magnesium, barium, strontium) suspended solids; mineral scales (calcium carbonate and barium sulfate); acid producing bacteria and sulfate reducing bacteria; friction reducers; iron solids (iron oxide and iron sulfide); dispersed clay fines, colloids and silts; acid gases (carbon dioxide, hydrogen sulfide); radionuclides (New York Generic Environmental Impact Statement).

[20]A detailed discussion of methane hydrates can be found in the Supplementary Paper SP 2.4 "Methane Hydrates," by Dr. Carolyn Ruppel, published on the MITEI website.

# Chapter 3: U.S. Gas Production, Use, and Trade: Potential Futures

## INTRODUCTION

As discussed in other sections of this report, many factors will influence the future role of natural gas in the U.S. energy system. Here we consider the most important of these: Greenhouse Gas (GHG) mitigation policy; technology development; size of gas resources; and global market developments. And we examine how they will interact to shape future U.S. gas use, production, and trade over the next few decades.

We investigate the importance of these factors and their uncertainties by applying established models of the U.S. and global economy (see Box 3.1). Alternative assumptions about the future allow us to create a set of scenarios that provides bounds on the future prospects for gas and illustrate the relative importance of different factors in driving the results.

The conditions explored include the High, Mean, and Low ranges of gas resource estimates described in Chapter 2. We show the impacts of various policy alternatives, including: no new climate policy; a GHG emission reduction target of 50% by 2050, using a price-based policy (such as a cap-and-trade system or emissions tax); and an emissions policy that uses a set of non-price regulatory measures.

Several assumptions have a particularly important effect on the analysis. Long-term natural gas supply curves, distinguishing the four gas types for the U.S. and Canada, are drawn from Chapter 2. U.S. economic growth is assumed to be 0.9% per year in 2005 to 2010, 3.1% in 2010 to 2020 (to account for recovery), and 2.4% for 2020 to 2050.

### BOX 3.1 GLOBAL AND U.S. ECONOMIC MODELS

Projections in this section were made using the MIT Emissions Prediction and Policy Analysis (EPPA) model and the U.S. Regional Energy Policy (USREP) model.[1] Both are multi-region, multi-sector representations of the economy that solve for the prices and quantities of energy and non-energy goods and project trade among regions.

The core results for this study are simulated using the EPPA model — a global model with the U.S. as one of its regions. The USREP model is nearly identical in structure to EPPA, but represents the U.S. only — segmenting it into 12 single and multi-state regions. In the USREP model, foreign trade is represented through import supply and export demand functions, broadly benchmarked to the trade response in the EPPA model. Both models account for all Kyoto gases.

The advantage of models of this type is their ability to explore the interaction of those factors underlying energy supply and demand that influence markets. The models can illustrate the directions and relative magnitudes of influences on the role of gas, providing a basis for judgments about likely future developments and the effects of government policy. However, results should be viewed in light of model limitations. Projections, especially over the longer term, are naturally subject to uncertainty. Also, the cost of technology alternatives, details of market organization, and the behavior of individual industries (e.g., various forms of gas contracts, political constraints on trade and technology choice) are beneath the level of model aggregation. The five-year time step of the models means that the effects of short-term price volatility are not represented.

**Table 3.1 Levelized Cost of Electricity (2005 cents/kWh)**

| | Reference | Sensitivity |
|---|---|---|
| Coal | 5.4 | |
| Advanced Natural Gas (NGCC) | 5.6 | |
| Advanced Nuclear[2] | 8.8 | 7.3 |
| Coal/Gas with CCS[3] | 9.2/8.5 | 6.9/6.6 |
| Renewables | | |
| Wind | 6.0 | |
| Biomass | 8.5 | |
| Solar | 19.3 | |
| Substitution elasticity (Wind, Biomass, Solar) | 1.0 | 3.0 |
| Wind+Gas Backup | 10.0 | |

Source: EPPA, MIT

Influential cost assumptions are shown in Table 3.1. The first column contains technology costs imposed in the main body of the analysis, as documented in Appendix 3A. The right-most column shows values to be employed in sensitivity tests to be explored later, where we vary the costs of competing generation technologies (nuclear, coal, and gas with carbon capture and storage and renewables). The intermittent renewables (wind and solar) are distinguished by scale. At low penetration levels, they enter as imperfect substitutes for conventional electricity generation, and the estimates of the levelized cost of electricity (LCOE[4]) apply to early installations when renewables are at sites with access to the best quality resources and to the grid, and storage or backup is not required. Through the elasticity of substitution, the model imposes a gradually increasing cost of production as their share increases, to be limited by the cost with backup. These energy sector technologies, like others in the model, are subject to cost reductions over time through improvements in labor, energy, and (where applicable) land productivity.

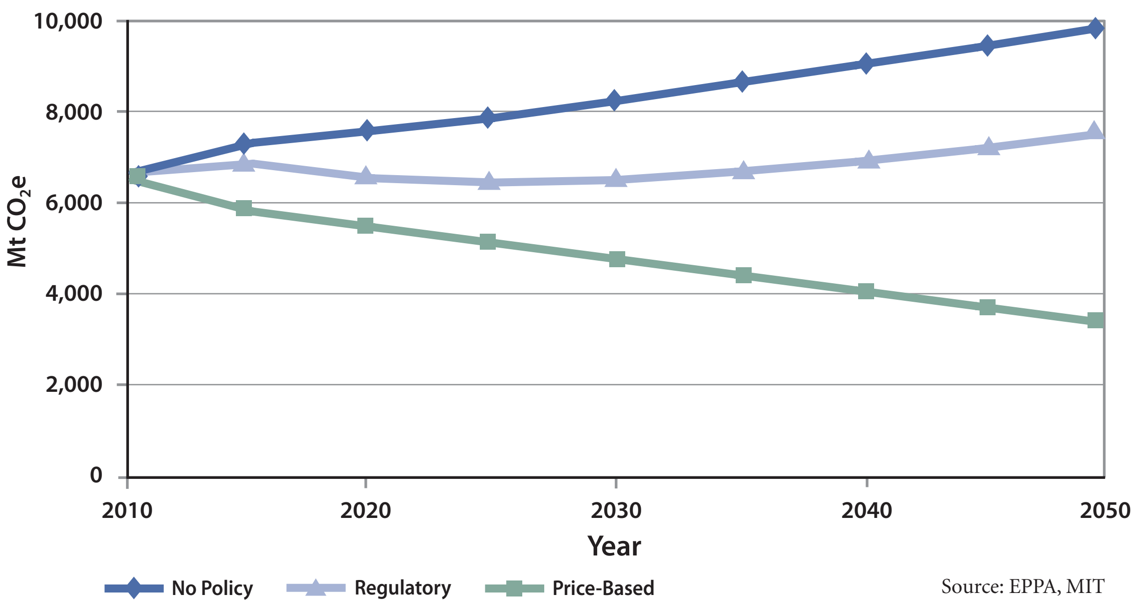
The potential role of compressed natural gas (CNG) in vehicles is considered separately, drawing on estimates of the cost of these vehicles from Chapter 5 of this report.

We also consider two possible futures for international gas markets: one where they continue in their current pattern of regional trading blocs and an alternative where there develops a tightly integrated global gas market similar to that which now exists for crude oil.

## THE ROLE OF U.S. CLIMATE POLICY — THREE ALTERNATIVE SCENARIOS

To explore the future of U.S. gas use in a carbon-constrained world, we analyze three scenarios of greenhouse control, with very different implications for the energy sector as a whole. Scenario 1 establishes a baseline, with no GHG policy measures beyond those in place today. Emissions grow by some 50% over the period, as shown in Figure 3.1. Scenarios 2 and 3 are constructed to span a wide range of possible approaches to climate policy, and potential effects on gas use. Scenario 2 assumes that a price-based policy is imposed on all U.S. GHG emissions with a target of a 50% reduction by 2050, as can be seen in Figure 3.1. Scenario 3 imposes no economy-wide target, but considers two measures proposed for the electric power sector: a renewable energy standard and measures to force retirement of coal-fired power plants. As seen in Figure 3.1, this scenario of a regulatory approach essentially stabilizes U.S. GHG emissions, yielding only about 10% increase by 2050.

**Figure 3.1 U.S. Greenhouse Gas Emissions under Alternative Scenarios**




Source: EPPA, MIT

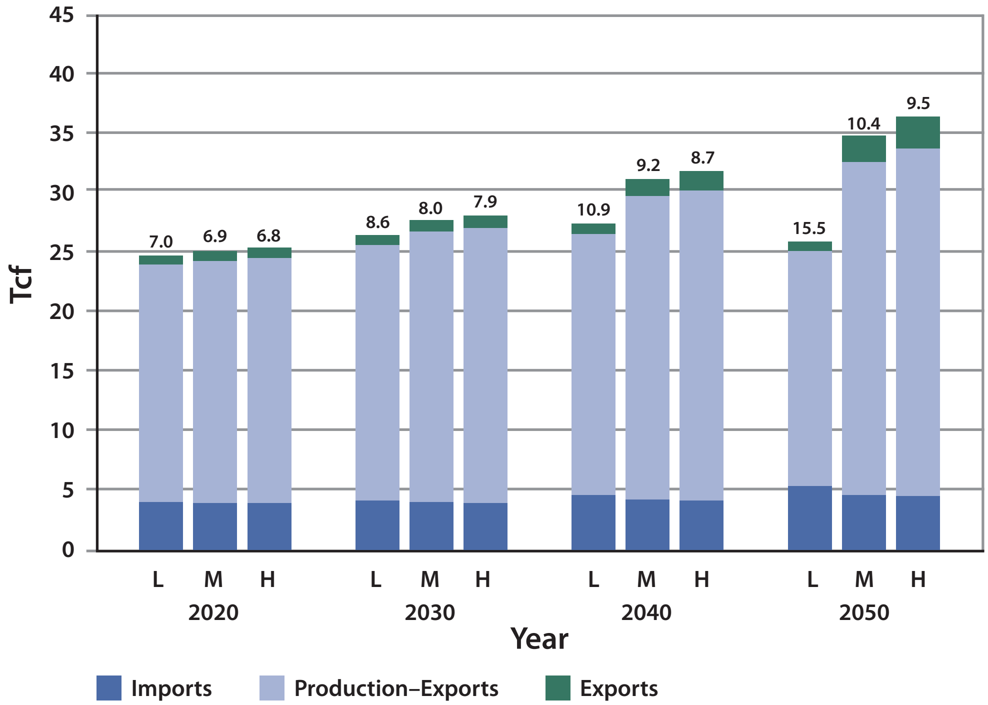
### Scenario 1 — No Additional GHG Mitigation Policy

Unless gas resources are at the Low end of the resource estimates in Chapter 2, domestic gas use and production are projected to grow substantially between now and 2050. This result is shown in Figure 3.2, from EPPA model simulations, on the assumption that global gas markets remain fragmented in regional trading blocs. Under the Mean resource estimate, U.S. gas production rises by around 40% between 2005 and 2050, and by a slightly higher 45% under the High estimate. It is only under the Low resource outcome that resource availability substantially limits growth in domestic production and use. In that case, gas production and use plateau around 2030 and are in decline by 2050.

The availability of shale gas resources has a substantial effect on these results. If the Mean estimate for other gas resources is assumed, and this same projection is made omitting the shale gas component of supply, U.S. production peaks around 2030 and declines to its 2005 level by 2050.

Given the continued existence of regional trading blocs for gas, there is little change in the role played by imports and exports of gas. Imports (mainly from Canada) are roughly constant over time, though they increase when U.S. resources are Low. Exports (principally to Mexico) are also maintained over the period and grow somewhat if U.S. gas resources are at the High estimate.

**Figure 3.2 U.S. Gas Use, Production, and Imports & Exports (Tcf), and U.S. Gas Prices above Bars ($/1,000 cf) for Low (L), Mean (M), and High (H) U.S. Resources. No Climate Policy and Regional International Gas Markets**




Source: EPPA, MIT

Gas prices (2005 U.S. dollars), shown at the top of the bars in Figure 3.2, rise gradually over time as the lower-cost resources are depleted; the lower the resource estimate, the higher the prices. The difference in prices across the range of resource scenarios is not great for most periods. In 2030, for example, the High resource estimate yields a price 2% below that for the Mean estimate, while the Low resource condition increased the price by 7%. The difference increases somewhat over time, especially for the Low resource case. By 2050, for example, the price is 8% lower if the High resource conditions hold, but 50% higher if domestic resources are at the Low estimate.

Underlying these estimates are developments on the demand side. Under Mean resources, electricity generation from natural gas would rise by about 70% over the period 2010 to 2050 though coal would continue to dominate, with only a slightly growing contribution projected from nuclear power and renewable sources (wind and solar). National GHG emissions rise by about 40% from 2005 to 2050. More detailed results for the scenarios with Mean resources are provided in Appendix 3B.

### Scenario 2 — Price-Based Climate Policy

An incentive- (or price-) based GHG emissions policy that establishes a national price on GHG emissions serves to level the emissions reduction playing field by applying the same penalty to emissions from all sources and all uses.

The policy explored here gradually reduces total U.S. GHG emissions, measured in $CO_2$ equivalents ($CO_2$-e)[5], to 50% below the 2005 level by 2050. The scenario is not designed to represent a particular policy proposal and no provision is included for offsets.

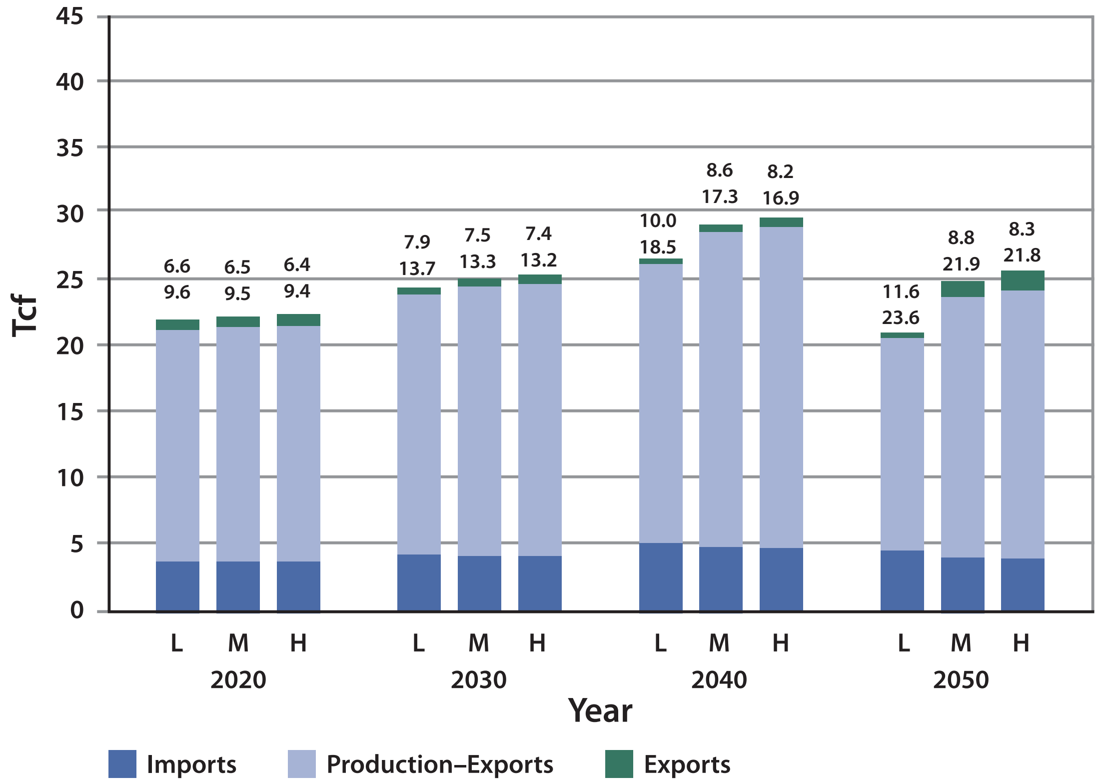
While measures taken abroad are not of direct interest for this study, such policies or the lack of them will affect the U.S. energy system through international trade. If the U.S. were to pursue this aggressive GHG mitigation policy, we assume that it would need to see similar measures being taken abroad. Thus, a similar pattern of reductions is assumed for other developed countries, with lagged reductions in China, India, Russia, Mexico, and Brazil that start in 2020 on a linear path to 50% below their 2020 levels by 2070. The rest of the developing countries are assumed to delay action to beyond 2050. We assume no emissions trading among countries.

*Even under the pressure of an assumed $CO_2$ emissions policy, total U.S. gas use is projected to increase up to 2050.*

The broad features of U.S. gas markets under the assumed emissions restriction are not substantially different from the no-policy scenario, at least through 2040 (Figure 3.3). Gas production and use grows somewhat more slowly, reducing use and production by a few Tcf in 2040 compared with the case without climate policy. After 2040, however, domestic production and use begin to fall. This decline is driven by higher gas prices, Carbon Dioxide ($CO_2$) charge inclusive, that gas users would see. The price reaches about $22 per thousand cubic feet (cf) with well over half of that price reflecting the $CO_2$ charge. While gas is less $CO_2$ intensive than coal or oil, at the reduction level required by 2050, its $CO_2$ emissions are beginning to represent an emissions problem.

However, even under the pressure of the assumed emissions policy, total gas use is projected to increase from 2005 to 2050 even for the Low estimate of domestic gas resources.

**Figure 3.3 U.S. Gas Use, Production and Imports & Exports (Tcf), and U.S. Gas Prices ($/1,000 cf) for Low (L), Mean (M), and High (H) U.S. Resources, Price-Based Climate Policy, and Regional International Gas Markets. Prices are shown without (top) and with (bottom) the emissions charge.**

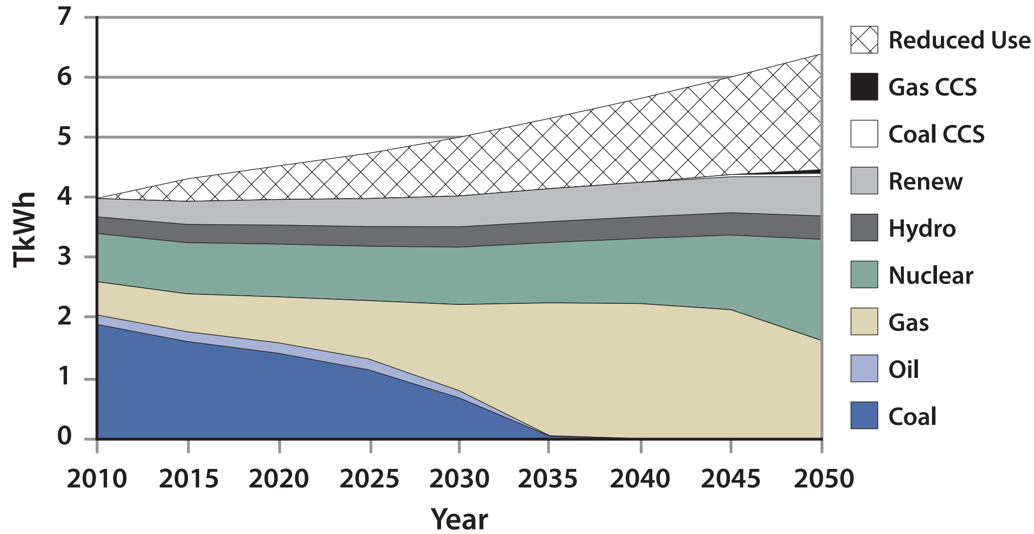



Source: EPPA, MIT

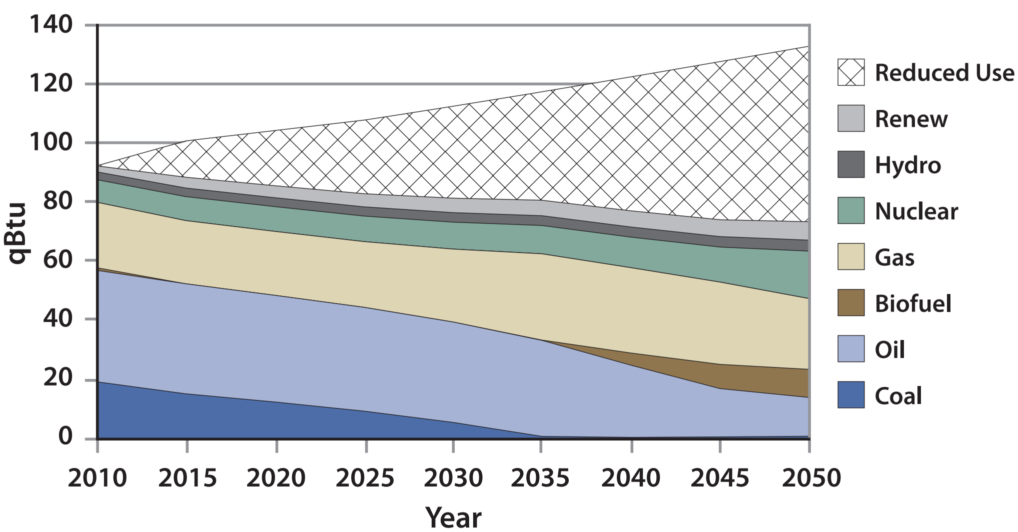
A major effect of the economy-wide, price-based GHG policy is to reduce energy use (Figure 3.4). The effect in the electric sector is to effectively flatten demand, holding it near its current 4 Trillion killowatt hour (TkWh) level (Figure 3.4a). Based on the cost assumptions underlying the simulation (see Appendix 3A) nuclear, Carbon Capture and Storage (CCS), and renewables are relatively expensive compared with generation from gas. Conventional coal is driven from the generation mix by the $CO_2$ prices needed to meet the economy-wide emissions reduction targets. Natural gas is the substantial winner in the electric sector: the substitution effect, mainly gas generation for coal generation, outweighs the demand reduction effect. For total energy (Figure 3.4b) the demand reduction effect is even stronger, leading to a decline in U.S. energy use of nearly 20 quadrillion ($10^{15}$) British thermal units (Btu). The reduction in coal use is evident, and oil and current-generation biofuels (included in oil) begin to be replaced by advanced biofuels. Because national energy use is substantially reduced, the share represented by gas is projected to rise from about 20% of the current national total to around 40% in 2040.

**Figure 3.4 Energy Mix under a Price-Based Climate Policy, Mean Natural Gas Resources**

**3.4a Electric Sector (TkWh)**




**3.4b Total Energy Use (qBtu)**



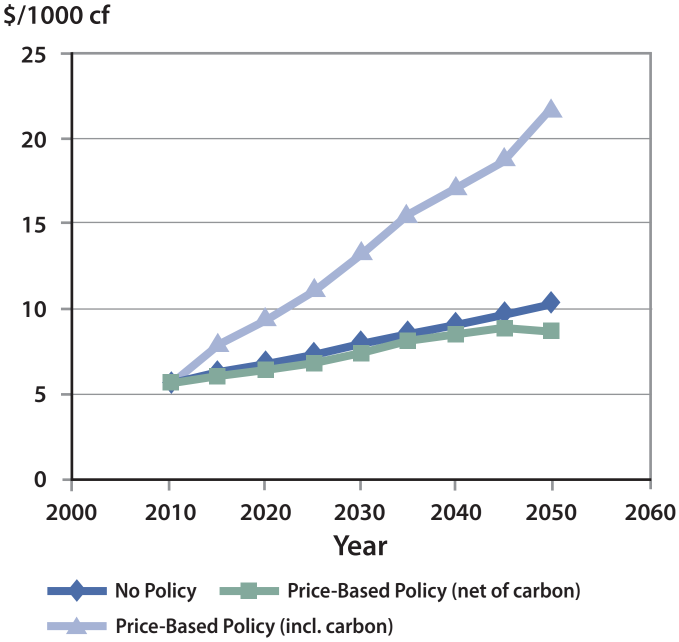

Source: EPPA, MIT

Under this policy scenario, the U.S. emissions price is projected to rise to $106 per ton $CO_2$-e in 2030 and to $240 by 2050. The macroeconomic effect is to lower U.S. Gross Domestic Product (GDP) by 1.7% in 2030 and 3.5% in 2050. (Other measures of cost are provided in Appendix 3A.) A selection of resulting U.S. domestic prices is shown in Figure 3.5. Natural gas prices, exclusive of the $CO_2$ price, are reduced slightly by the mitigation policy, but the price inclusive of the $CO_2$ charge is greatly increased (Figure 3.5a). The $CO_2$ charge is nearly half of the user price of gas.[6]

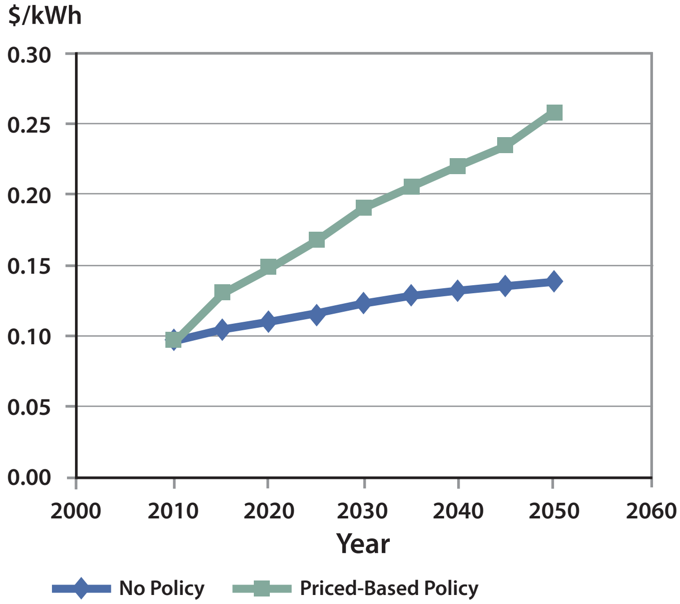
Even in the No-Policy case, electricity prices are projected to rise by 30% in 2030 and about 45% over the period to 2050 (Figure 3.5b). The assumed emissions mitigation policy is projected to cause electricity prices to rise by almost 100% in 2030 and by two and one-half times by 2050 compared with current prices.

**Figure 3.5 U.S. Natural Gas and Electricity Prices under Alternative Policy Scenarios, Mean Gas Resources**

**3.5a Natural Gas Prices ($/1000 cf)**




**3.5b Electricity Prices ($/kWh)**




Source: EPPA, MIT

As noted earlier, a set of alternative cost assumptions was explored for low-carbon technologies in the electricity sector, including less costly CCS, nuclear, and renewables (Table 3.1).

*The biggest projected impact on gas use in electricity results from an assumption of low-cost nuclear generation.*

Of these, the biggest impact on gas use in electricity results from low-cost nuclear generation. Focusing on 2050, when the effects of alternative assumptions are the largest, a low-cost nuclear assumption reduces annual gas use in the electric sector by nearly 7 Tcf. Economy-wide gas use falls by only about 5 Tcf, however, because the resulting lower demand for gas in electricity leads to a lower price and more use in other sectors of the economy.

Lower-cost renewables yield a reduction in gas use in the electric sector by 1.8 Tcf in 2030, but total gas use falls by only 1.2 Tcf. In 2050, a difference in gas use is smaller, 0.5 Tcf and 0.1 Tcf respectively, as availability of cheaper renewables displaces nuclear power which by that time starts to replace gas in the electric sector. With less-costly CCS, gas use increases in the electric sector by nearly 3 Tcf. This is because both gas generation with CCS and coal generation with CCS become economic and share the low-carbon generation market (with about 25% of electricity produced by gas with CCS by 2050 and another 25% by coal with CCS). Gas use in the economy as a whole increases even more, by 4.2 Tcf.[7]

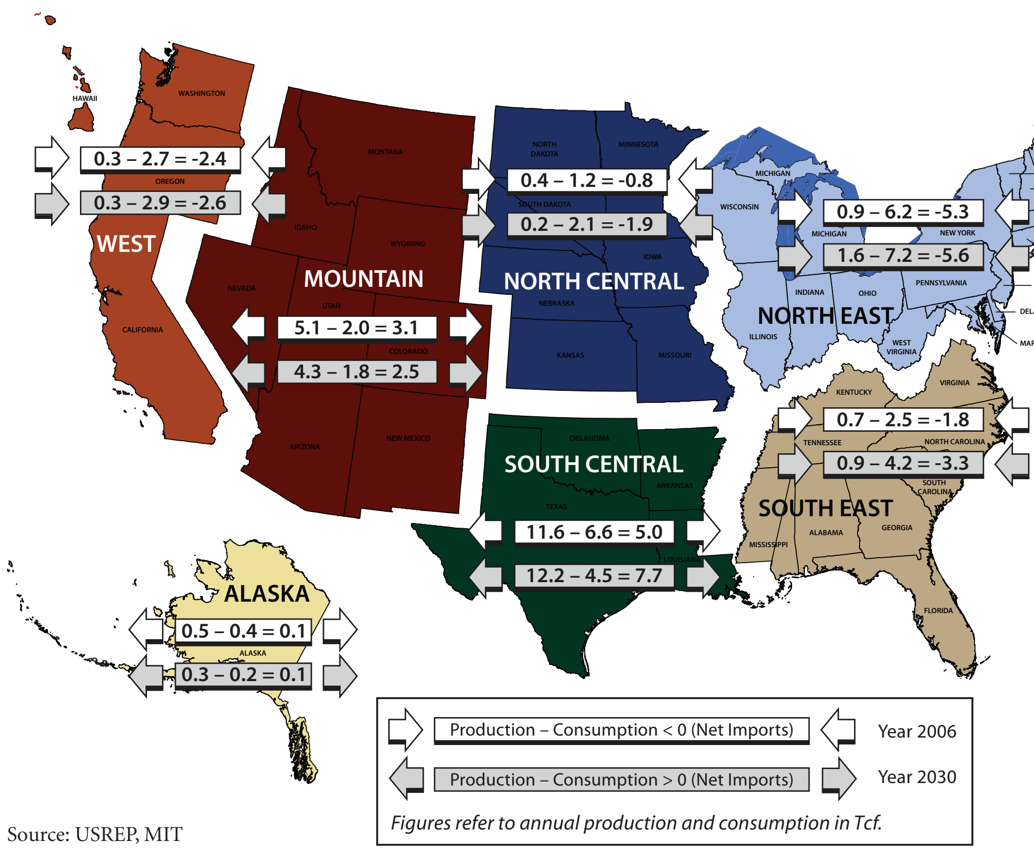
Many other combinations of technological uncertainties could be explored. For example, a breakthrough in large-scale electric storage would improve the competitiveness of intermittent sources. A major insight to be drawn from these few model experiments, however, is that, under a policy based on emissions pricing to mitigate greenhouse gas emissions, natural gas is in a strong competitive position unless competing technologies are much less expensive than we now anticipate.

The simulations shown in Figures 3.3–3.5 do not include the CNG vehicle. When this policy case is repeated with this technology included, applying optimistic cost estimates drawn from Chapter 4 of this report, the result depends on the assumption about the way competing biofuels, and their potential indirect land-use effects, are accounted. Even with advanced biofuels credited as a zero-emissions option, however, CNG vehicles rise to about 15% of the private vehicle fleet by 2040 to 2050. They consume about 1.5 Tcf of gas at that time which, because of the effect of the resulting price increase on other sectors, adds approximately 1.0 Tcf to total national use.[8]

Some U.S. regions that have not traditionally been gas producers have significant shale gas resources, and the extent to which these resources are developed is material to the patterns of production and distribution of gas in the U.S. To identify regional patterns of production and use within the U.S., we apply the USREP model and report results for seven regions of the country for 2006 and 2030 under the 50% climate policy target and the Mean gas resources (Figure 3.6). Gas production increases most in those regions with the new shale resources — by more than 78% in the Northeast region (New England through the Great Lakes States) and by about 50% in the South Central area that includes Texas. In regions without new shale resources,

*Some U.S. regions that have not traditionally been gas producers do have significant shale gas resources, and the extent to which these resources are developed is material to the patterns of production and distribution of gas in the U.S.*

**Figure 3.6 Natural Gas Production and Consumption by Region in the U.S., 2006 and 2030, Price-Based Policy Scenario, Mean Gas Resources**




Source: USREP, MIT

production changes little, showing slight increases or decreases. In the Northeast, the production increase comes close to matching the projected growth in gas use.

The most substantial potential need for additional interregional gas flows, on the regional definition of Figure 3.6, is from the Texas/South Central region which increases net exports by a combined 2.7 Tcf, with shipment to other regions except the Northeast.[9] Compared to the 2030 interregional flows absent climate policy, the assumed emissions target lowers the need for new capacity largely because of the expansion of supply in the Northeast.

*Among the most obvious measures that could have a direct impact on $CO_2$ emissions would be those requiring renewable energy and one encouraging a phase-out of existing coal-fired power plants.*

### Scenario 3 — Regulatory Emissions Reductions

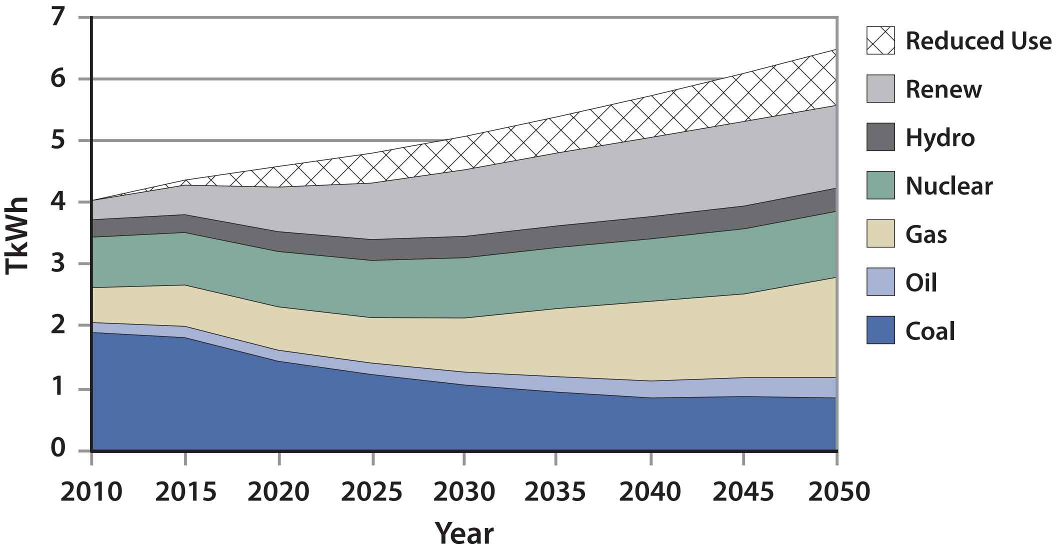
If emissions reductions are sought by regulatory and/or subsidy measures, with no price on emissions, many alternatives are available. Among the most obvious measures that could have a direct impact on $CO_2$ emissions would be those requiring renewable energy and one encouraging a phase-out of existing coal-fired power plants.

To explore this prospect, we formulate a scenario with a renewable energy standard (RES) mandating a 25% share of electric generation by 2030, and holding at that level through 2050, and measures to force retirement of coal-fired power plants starting in 2020, so that coal plants accounting for 55% of current production are retired by 2050. Mean gas resources are assumed, as are the reference levels of all technology costs. This case results in approximately a 50% reduction in carbon emissions in the electricity sector by 2050, but it does not provide incentives to reduction in non-electric sectors so these measures only hold total national GHG emissions to near the 2005 level, as shown in Figure 3.1.

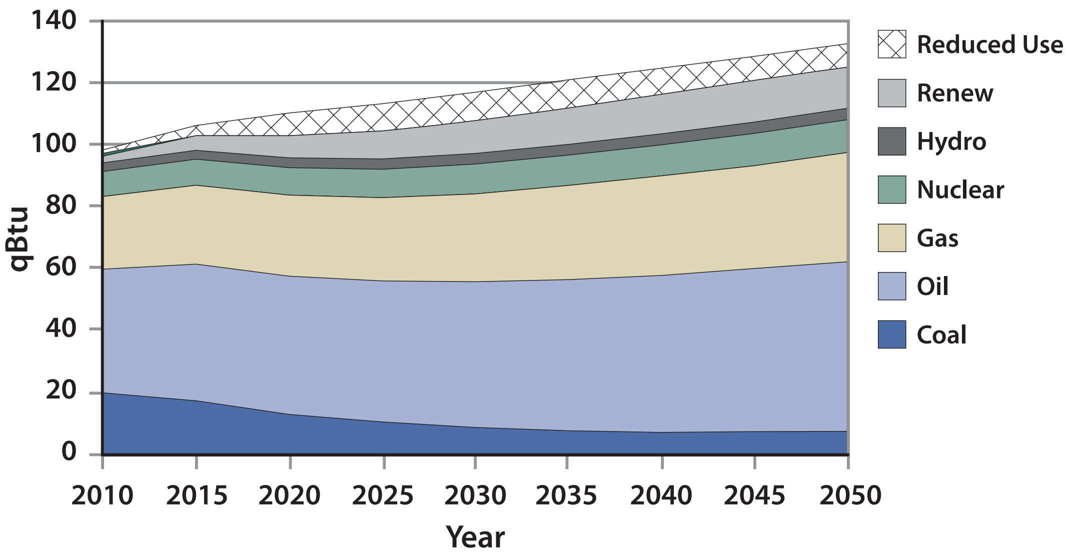
One evident result of these mitigation measures is that the reduction in energy demand is less than under the assumed price-based policy, either in the electric sector (Figure 3.7a) or in total energy (Figure 3.7b). Also, the measures represented here achieve less emissions reduction in the electricity sector than does the price-based policy. In the price-based policy, reductions in the electricity sector are about 70% by 2050, even though the national target is only a 50% reduction, because it is less costly to abate there than in the rest of the economy. The difference in total national energy use is more dramatic (Figure 3.7b compared with Figure 3.4b) because the all-sector effect of the universal GHG price is missing.

**Figure 3.7 Energy Mix under a Regulatory Policy, Mean Gas Resources**

**3.7a Electric Sector (TkWh)**




**3.7b Total Energy Use (qBtu)**




Source: EPPA, MIT

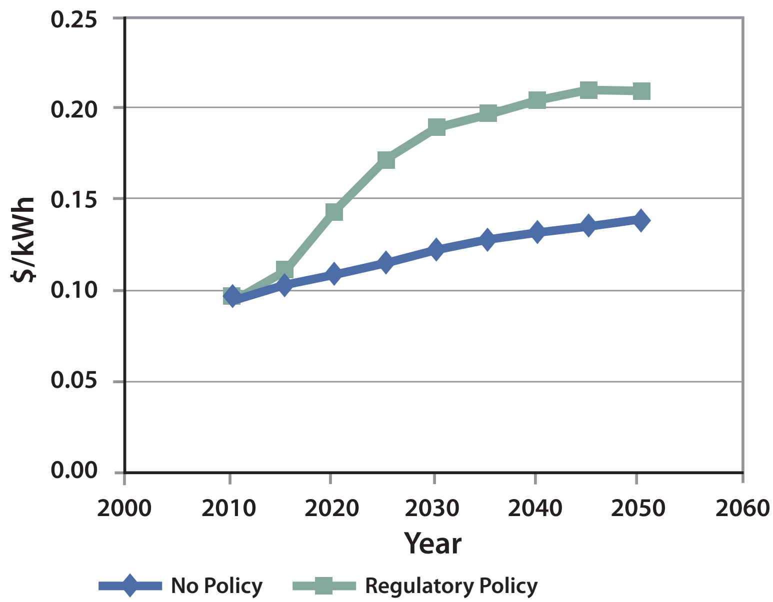
These regulatory measures yield a projection of total U.S. gas use very similar to that under a no-policy assumption, shown in Figure 3.2. Under the Mean resource estimate the 2050 level is almost identical between the two scenarios (see Appendix 3B), and the figure would look essentially the same for the High and Low cases as well. Also, U.S. natural gas prices are essentially the same with these regulatory measures as in the case without additional GHG policy shown in Figure 3.5a (again see Appendix 3B for a comparison). Electricity prices do differ from the no-policy scenario, however, as higher generation costs are passed along to consumers. The result is presented in Figure 3.8, where by 2050 the coal and renewable regulations raise the electricity price by 50% over its level without GHG policy.

In this case, the effects on natural gas, compared to a no-policy assumption, are concentrated in the electric sector as the non-electric sectors face roughly the same gas price in both cases.

*Natural gas remains resilient under a wide range of potential approaches to U.S. climate policy.*

In the electric sector, the forced expansion of renewables tends to squeeze out gas-based electric generation, particularly in the early decades of the period, while the reduction in coal use opens up opportunities for gas. The net result is a pattern of gas use over time not different from the no-policy case, as noted earlier. Naturally, the net impact on gas use in the electric sector depends on the stringency of the two regulatory measures and their relative pace of implementation, and compared to the assumed price-based approach, they have the potential to reduce the use of gas in the sector. Nonetheless, for this regulatory scenario, like the more ambitious policy-based case, U.S. natural gas demand remains resilient, continuing to make a major contribution to national energy use.

**Figure 3.8 Electricity Prices ($/kWh) under No-Policy and Regulatory Scenarios, Mean Gas Resources**




Source: EPPA, MIT

## THE ROLE OF INTERNATIONAL GAS MARKETS

Currently world gas trade is concentrated in three regional markets: North America; Europe — served by Russia and Africa; and Asia — with a link to the Middle East. There are significant movements of gas within each of these markets, but limited trade among them.

Different pricing structures hold within these regional markets. For some transactions, prices are set in liquid competitive markets; in others they are dominated by contracts linking gas prices to prices of crude oil and oil products. As a result, gas prices can differ substantially among the regions.

These relatively isolated, regionalized markets could be sustained for many more decades. On the other hand, it is possible that LNG or pipeline transport could grow, linking these three regions, with the effect of increasing interregional gas competition, loosening price contracts tied to oil products, and moderating the price deviations among the regions.

Such a process could go in many directions depending on the development of supply capacity by those nations with very large resources (mainly Russia and countries in the Middle East) or perhaps the expansion of non-conventional sources elsewhere. To the extent the structure evolves in this direction, however, there are major implications for U.S. natural gas production and use.

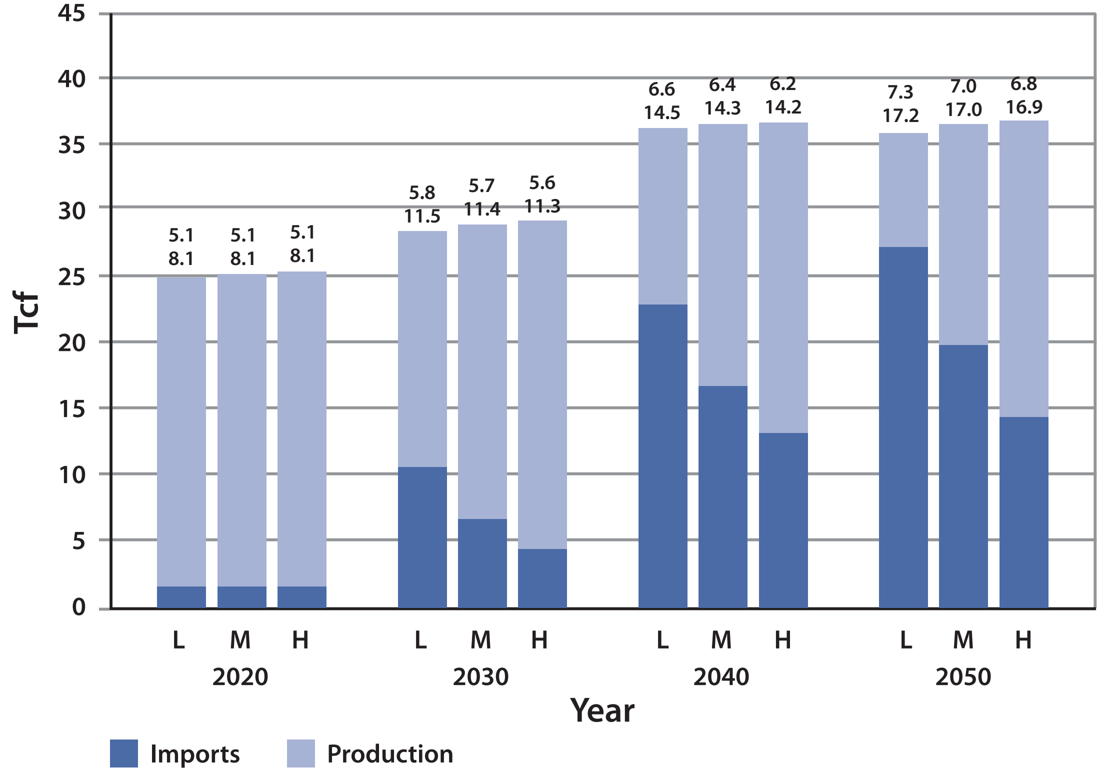
To investigate the end effect of possible evolution of an integrated global market akin to crude oil, we simulate a scenario where market integration and competition lead to equalization of gas prices among markets except for fixed differentials that reflect transport costs.

In this scenario, gas suppliers and consumers are assumed to operate on an economic basis. That is, no effective gas cartel is formed, and suppliers exploit their gas resources for maximum national economic gain.

Projected effects on U.S. production and trade are shown in Figure 3.9 for the 50% reduction and High, Mean, and Low gas resources cases. This result may be compared with the Regional Markets case shown in Figure 3.3.

In 2020, U.S. net imports are lowered to 1.6 Tcf (versus 4.1 Tcf in the Regional Markets case). Because in the Integrated Global Market scenario the EPPA model resolves for the net trade only, a decrease in net imports might be interpreted as a potential for small gas exports from the U.S. while keeping imports constant. Beginning in the period 2020 to 2030, the cost of U.S. gas begins to rise above that of supplies from abroad and the U.S. becomes more dependent on imports of gas. In the Mean resource case, the U.S. depends on imports for about 50% of its gas by 2050 and U.S. gas use rises to near the level in the no-policy case, because prices are lower. As the emergence of an integrated global market would lead ultimately to greater reliance on imports, U.S. gas use — and prices — are much less affected by the level of domestic resources. Thus, the development of a highly integrated international market, with decisions about supply and imports made on an economic basis, would have complex effects: it would benefit the U.S. economically, limiting the development of domestic resources but would lead to growing import dependence.

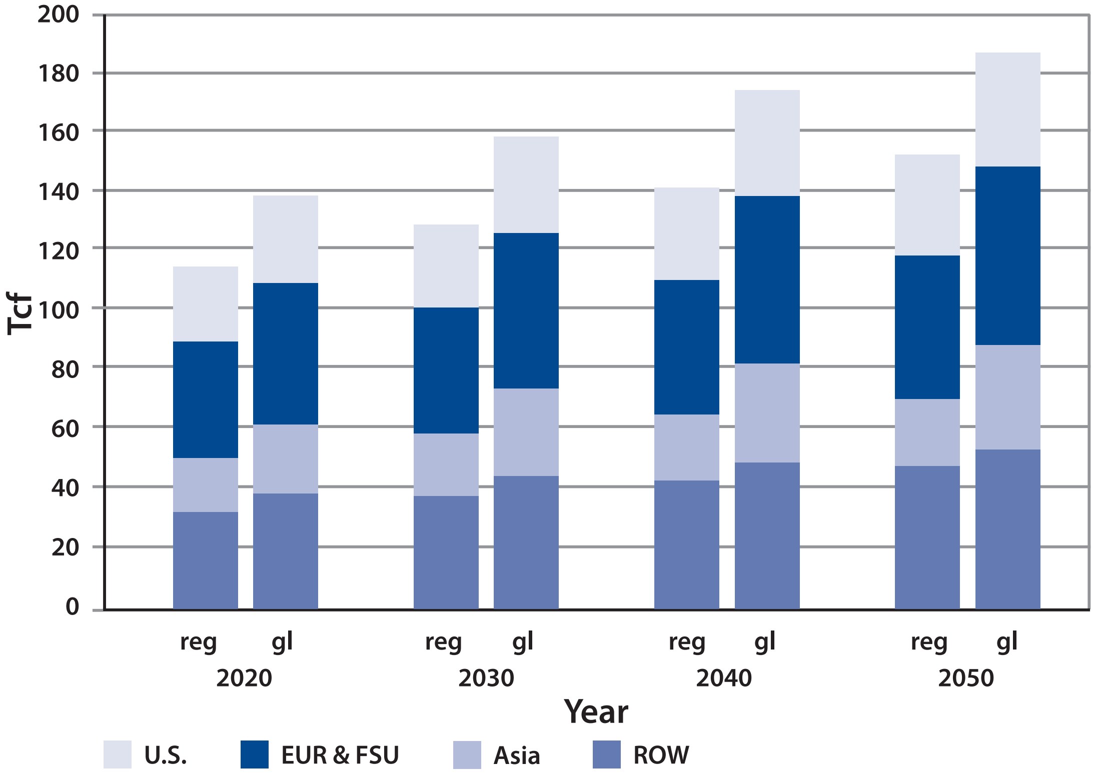
**Figure 3.9 U.S. Gas Use, Production and Imports & Exports (Tcf), and U.S. Gas Prices ($/1,000 cf) for Low (L), Mean (M), and High (H) U.S. Resources, Price-Based Climate Policy, and Global Gas Markets. Prices are shown without (top) and with (bottom) the emissions charge.**




Source: EPPA, MIT

In the Regional Markets case, global demand for gas increases from the current demand of about 100 Tcf, to about 150 Tcf by 2050. In the Integrated Global Markets scenario, gas availability increases globally, reducing gas prices, and as a result, gas demand rises to about 190 Tcf in 2050. Figure 3.10 shows the projected increase in gas use. In the Regional Markets case, gas use in U.S. and Asia grows by around 50% from 2010 to 2050, while in Europe and countries of the former Soviet Union it increases by about 35%. Assumption of an Integrated Global Market changes the growth in Asia to 135%, while U.S. and European use grows by about 70%. A growth in the Rest of the World (ROW) is mostly driven by an increase in the gas usage in the Middle East and the rest of Americas, where assumptions about the different market structures affect the results to a lesser degree.

**Figure 3.10 Gas Use (Tcf) in Regional Markets (reg) and Integrated Global Markets (gl) Scenarios for U.S., Asia, Europe and Former Soviet Union (EUR+FSU), and the Rest of the World (ROW)**




Source: EPPA, MIT

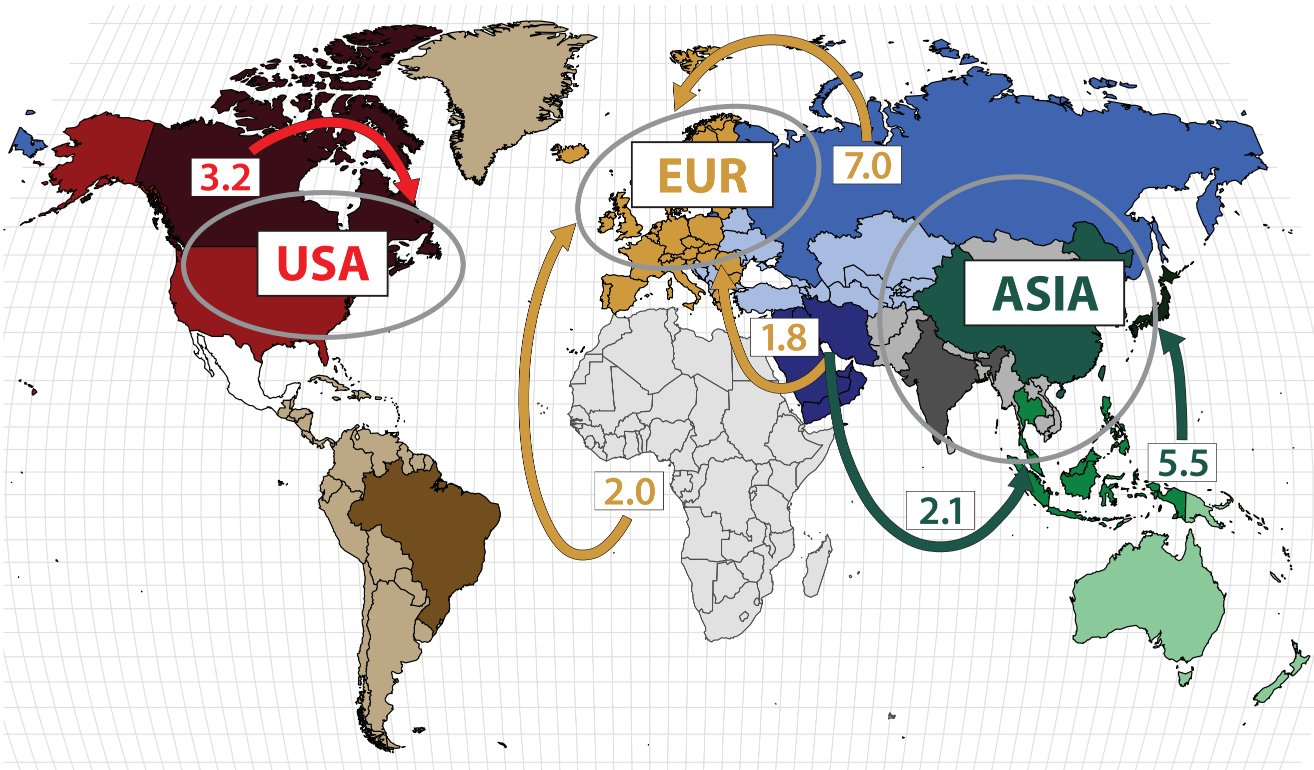
Possible international gas trade flows that are consistent with U.S. and global demand under the Regional and Integrated Global Markets cases are shown in Figure 3.11. Under Regional Market conditions (Figure 3.11a), we can see that trade flows are large within gas market regions but small among them. To avoid a cluttered map, small trade flows (less than 1 Tcf) are not shown. Except for the "Middle East to Europe" flow of 1.8 Tcf, interregional movements among the three regions specified above are less than 0.6 Tcf in any direction in 2030.

Trade flows can be particularly sensitive to the development of transportation infrastructure and political considerations, and so projections of bilateral trade in gas are highly uncertain. The Regional Markets case tends to increase trade among partners where trade already exists, locking in patterns determined in part by historical political considerations.

If a highly integrated Global Market is assumed to develop (Figure 3.11b), a very different pattern of trade emerges. The U.S. is projected to import from the Middle East as well as from Canada and Russia, and movements from the Middle East to Asia and Europe would increase implying a substantial expansion of Liquefied Natural Gas (LNG) — facilities. Russian gas would begin to move into Asian markets, via some combination of pipeline transport and LNG.

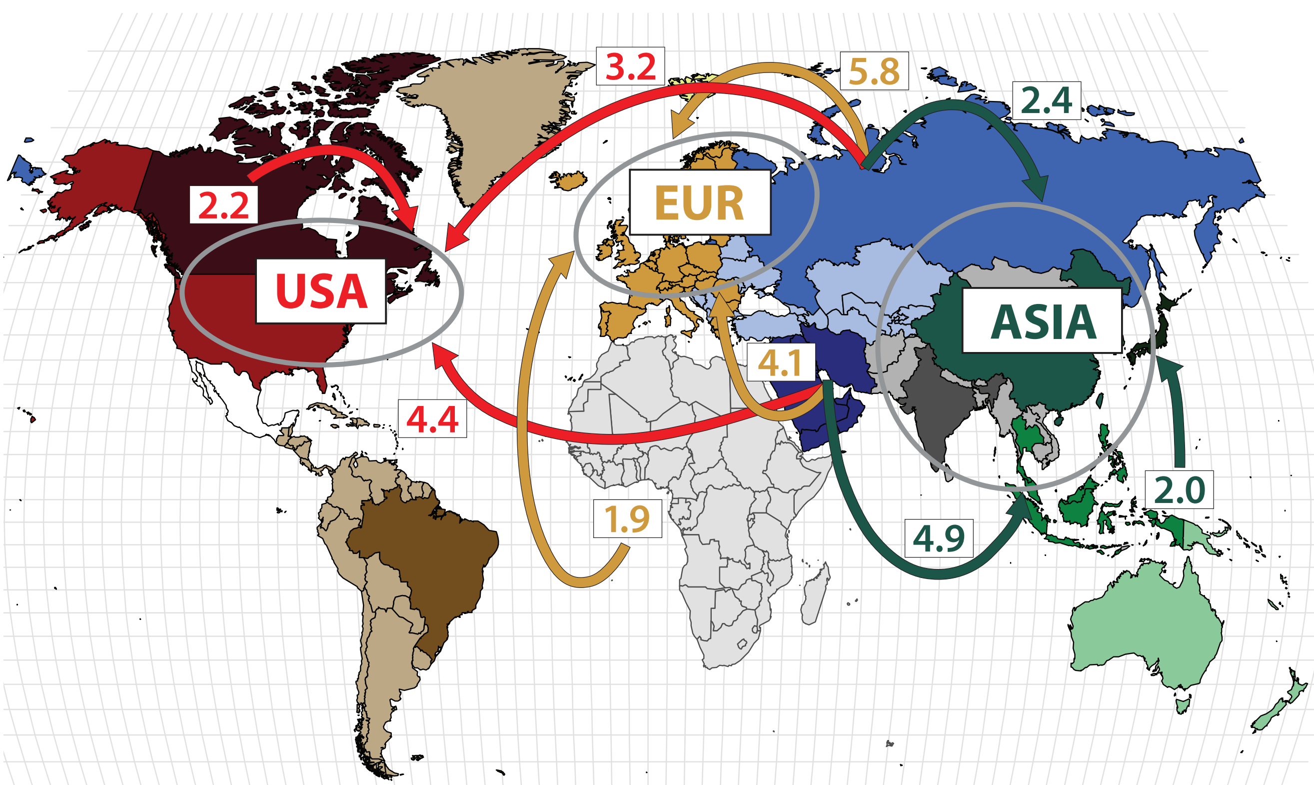
**Figure 3.11 Major Trade Flows of Natural Gas among the EPPA Regions in 2030, No New Policy (Tcf)**

**3.11a Regional Markets**




Source: EPPA, MIT

**3.11b Global Market**




Source: EPPA, MIT

The precise patterns of trade that might develop to 2030 and beyond will be influenced by the economics of the energy industry, as captured by the EPPA model, and also by national decisions regarding gas production, imports, and transport infrastructure. Therefore, the numbers shown are subject to a number of uncertainties, prominent among which is the willingness of Middle East and Russian suppliers to produce and export on the modeled economic basis.[10] If potential supplies are not forthcoming, then global prices would be higher and the U.S. would import less than projected and perhaps increase exports. The broad insight to be drawn is nonetheless evident: to the degree that economics are allowed to determine the global gas market, trade in this fuel is set to increase over coming decades, with implications for investment and potential concerns about import dependence.

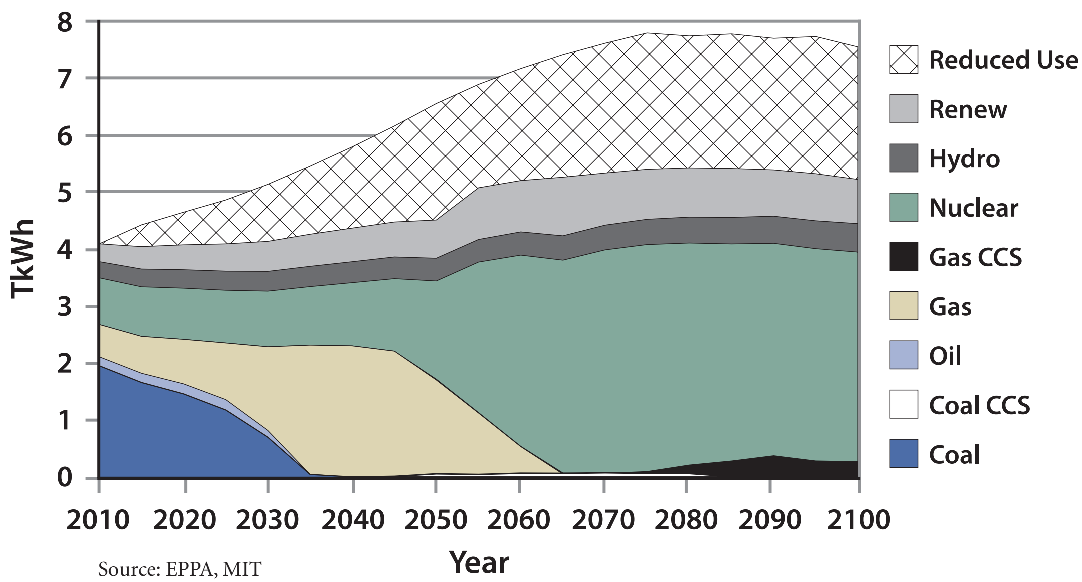
The assumptions about the gas markets also affect the carbon price and GDP impacts in the GHG mitigation scenario. While the difference is small initially (in 2030, a U.S. carbon price is decreased from \$106 to \$103 per ton $CO_2$-e and U.S. GDP loss is decreased from 1.7% to 1.6%), it grows over time (in 2050, a U.S. carbon price is decreased from \$240 to \$180 and U.S. GDP loss is decreased from 3.5% to 2.6%).

## LONGER-TERM PROSPECTS FOR GAS UNDER DEEPER EMISSIONS CUTS

While current investment and policy decisions appropriately focus on a shorter horizon, policy decisions related to atmospheric stabilization of GHG concentrations inevitably involve a very long-term perspective. Though gas frequently is touted as a “bridge” to the future, continuing effort is needed to prepare for that future, lest the gift of greater domestic gas resources turn out to be a bridge with no landing point on the far bank.

To explore this issue, we conducted model simulations extending the horizon to 2100 assuming GHG emissions cuts that deepen to 80% below 2005 levels. The result is that, until gas with CCS begins to penetrate after 2060, the cost of $CO_2$ emissions from gas generation becomes too high to support its use in generation (Figure 3.12). Nuclear is cheaper than coal or gas with CCS for much of the period and so it expands to meet the continuing electricity demand. Different cost assumptions well within the range of uncertainty would lead to a different mix of low-$CO_2$ generation sources, but the picture for gas without CCS would remain the same.

**Figure 3.12 Energy Mix in Electric Generation under a Price-Based Climate Policy, Mean Natural Gas Resources, and Regional Natural Gas Markets (TkWh)**




Source: EPPA, MIT

One implication of this longer-term experiment is that while we might rely on plentiful supplies of domestic gas in the near term, this must not detract us from preparing for a future with even greater GHG emissions constraints. Barriers to the expansion of nuclear power or coal and/or gas generation with CCS must be resolved over the next few decades so that over time these energy sources will be able to replace natural gas in power generation. Without such capability, it would not be possible to sustain an emissions mitigation regime.

*To the degree that economics are allowed to determine the global gas market, trade in this fuel is set to increase over coming decades, with implications for investment and import dependence.*

## CONCLUSIONS

The outlook for gas over the next several decades is in general very favorable. In the electric generation sector, given the unproven and relatively high cost of other low-carbon generation alternatives, gas could well be the preferred alternative to coal.

A multi-sector GHG pricing policy would increase gas use in generation but reduce its use in other sectors, on balance increasing gas use substantially from the present level. A regulatory approach, applied to renewable and coal use in the electric sector, could lead to even greater growth in gas use while having a more limited effect on national GHG emissions. Most important, in all cases studied — no new climate policy and a wide range of approaches to GHG mitigation — natural gas is positioned to play a growing role in the U.S. energy economy.

International gas resources are likely less costly than those in the U.S. except for the lowest-cost domestic shale resources, and the emergence of an integrated global gas market could result in significant U.S. gas imports.

The shale gas resource is a major contributor to domestic resources but far from a panacea over the longer term. Under deeper cuts in $CO_2$ emissions, cleaner technologies are needed. Gas can be an effective bridge to a lower $CO_2$ emissions future but investment in the development of still lower $CO_2$ technologies remains an important priority.

## NOTES

[1]Citations to documentation of the EPPA model and features related to this study are provided in Paltsev, S., H. Jacoby, J. Reilly, O. Kragha, N. Winchester, J. Morris, and S. Rausch, 2010: The Future of U.S. Natural Gas Production, Use, and Trade. MIT Joint Program on the Science and Policy of Global Change, *Report 186*, Cambridge, MA. The USREP model is described by Rausch, S., G. Metcalf, J. Reilly, and S. Paltsev, 2010: Distributional Impacts of Alternative U.S. Greenhouse Gas Control Measures. MIT Joint Program on the Science and Policy of Global Change, *Report 185*, Cambridge, MA.

[2]Reference costs from the U.S. EIA (see Appendix 3A). The lower sensitivity estimate is based on Update of the 2003 Future of Nuclear Power: An Interdisciplinary MIT study, Massachusetts Institute of Technology, Cambridge, MA.

[3]Reference costs from the U.S. EIA (see Appendix 3A). The lower sensitivity estimate for coal with CCS draws on The Future of Coal: An Interdisciplinary MIT study, Massachusetts Institute of Technology, Cambridge, MA; that for gas with CCS comes from McFarland, J., S. Paltsev, and H. Jacoby, 2009: Analysis of the Coal Sector under Carbon Constraints, *Journal of Policy Modeling*, 31(1), 404–424.

[4]LCOE is the cost per kWh that over the life of the plant fully recovers operating, fuel, capital, and financial costs.

[5]$CO_2$ equivalent emissions for all greenhouse gases are calculated using 100-year global warming potentials (GWPs). See Appendix 1A for discussion. The simulations in this chapter account for fugitive methane emissions from the gas supply system.

[6]Because of the limited opportunities for gas-oil substitution the current price premium in the U.S. of oil products over gas (on an energy basis) is maintained and even grows over time. One substitution option not modeled here is the possibility of conversion of gas to liquids, which might become economic and perhaps be further stimulated by security concerns, even though making no contribution to $CO_2$ reduction. Such a development would raise U.S. gas use and prices, and lower oil demand with some moderating effect on the world oil price.

[7]For more details about sensitivity tests see Paltsev, S., H. Jacoby, J. Reilly, Q. Ejaz, F. O'Sullivan, J. Morris, S. Rausch, N. Winchester, and O. Kragha. 2010: The Future of U.S. Natural Gas Production, Use, and Trade, MIT Joint Program on the Science and Policy of Global Change, *Report 186*, Cambridge, MA.

[8]Substitution for motor fuel is the likely target of possible expansion of gas-to-liquids technology (see Chapter 4). Its market penetration would depend on competition not only with oil products but also with direct gas use, biofuels, and electricity which reduce $CO_2$ emissions while liquids from gas would not.

[9]Gas production and use with the USREP model is somewhat lower than the EPPA projection. Compared to EPPA, the USREP model has the advantage of capturing inter-regional differences in coal and gas prices, and better reflecting differences in renewable costs among regions, but it does not represent foreign trading partners. This variation introduced by the different model structures is well within the range of other uncertainties.

[10]For additional scenarios about the long-term prospects for Russian natural gas, see Paltsev S., (2011). Russia's Natural Gas Export Potential up to 2050. MIT Joint Program on the Science and Policy of Global Change Report (forthcoming).

# Chapter 4: Electric Power Generation

## INTRODUCTION

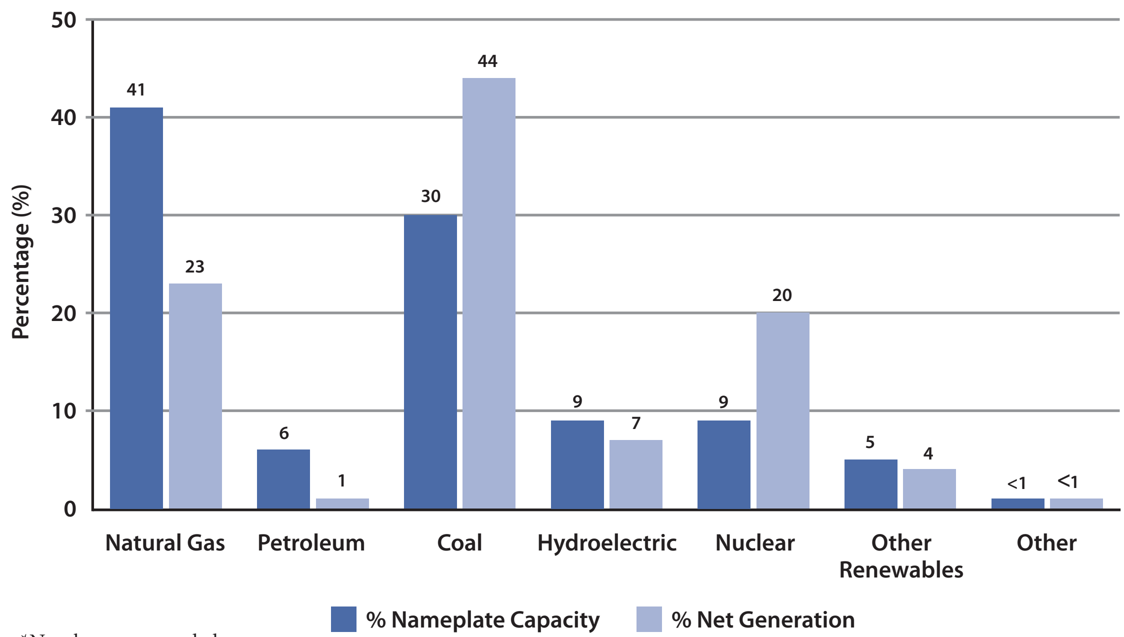
The low-carbon emissions and low capital cost of natural gas generation compared to other fossil fuel generation, combined with abundant gas supplies and current relatively low prices, make natural gas an attractive option in a carbon-constrained environment, such as that contemplated in the analysis in Chapter 3. In addition to its increasingly important role as a primary fuel for electricity generation, natural gas will continue to perform a unique function in the power sector by providing both baseload power and the system flexibility that is required to meet variation in power demand and supply from intermittent sources.

The focus of this chapter is on the role of natural gas in helping to reduce $CO_2$ emissions from the power sector and the interaction of gas use with projected growth in wind and solar generation.

Natural gas provides flexibility to the power system largely through the three types of generation technologies: highly efficient natural gas combined cycle (NGCC) units, steam turbines, and gas turbines. Gas turbines are generally used to meet peak demand levels and to handle weather, time of day, seasonal, and unexpected changes in demand. NGCCs and steam turbines can act as baseload or intermediate-load units, although the majority of gas capacity in the U.S. now operates in load-following (intermediate) or peaking service.

Currently, natural gas is second only to coal in total generation, fueling 23% of U.S. electricity production. Natural gas, however, has the highest percentage of nameplate[1] generation capacity of any fuel, at 41% compared to 31% for coal, which is the next highest (Figure 4.1). This difference between nameplate capacity and generation is

**Figure 4.1 % Nameplate Capacity Compared to % Net Generation, U.S., 2009***




*Numbers are rounded
Source: MIT from EIA data

**BOX 4.1 MODELS EMPLOYED TO EXAMINE THE U.S. ELECTRICITY SYSTEM**

The MARKAL (MARKet ALlocation) model of the U.S. electricity sector enables a granular understanding of generation technologies, time-of-day and seasonal variations in electricity demand, and the underlying uncertainties of demand. It was originally developed at Brookhaven National Laboratory (L.D. Hamilton, G. Goldstein, J.C. Lee, A. Manne, W. Marcuse, S.C. Morris, and C-O Wene, "MARKAL-MACRO: An Overview," Brookhaven National Laboratory, #48377, November 1992). The database for the U.S. electric sector was developed by the National Risk Management Laboratory of the U.S. Environmental Protection Agency (EPA).

The Renewable Energy Deployment System (ReEDS) model is used to project capacity expansions of generation, incorporating transmission network impacts, associated reliability considerations and dispatch of plants as operating reserves. It also captures the stochastic nature of intermittent generation as well as temporal and spatial correlations in the generation mix and demand. It has been developed by the National Renewable Energy Laboratory (NREL) (J. Logan, P. Sullivan, W. Short, L. Bird, T.L. James, M. R. Shah, "Evaluating a Proposed 20% National Renewable Portfolio Standard," 35 pp. NREL Report No. TP-6A2-45161, 2009).

The Memphis model realistically simulates the hourly operation of existing generation plants in the presence of significant volumes of wind and solar generation. It was developed by the Institute for Research in Technology of Comillas University (Madrid, Spain) for the Spanish Electricity Transmission System Operator (Red Eléctrica de España) to integrate renewable energies. (A. Ramos, K. Dietrich, J.M. Latorre, L. Olmos, I.J. Pérez-Arriaga, "Sequential Stochastic Unit Commitment for Large-Scale Integration of RES and Emerging Technologies," 20th International Symposium of Mathematical Programming (ISMP) Chicago, IL, USA, August 2009.

http://www.iit.upcomillas.es/~aramos/ROM.htm

explained in part by the overbuilding of NGCC units in the mid-1990s. It also shows that NGCC units are operating well below their optimal operating value. Finally, it highlights the unique role of gas and steam turbines, which in 2009 had an average capacity factor of 10% (see Table 4.1). This low-capacity factor illustrates the peaking function of these units, particularly the gas turbines, that are routinely used only to meet peak demand levels and which, absent breakthroughs in storage, are essential for following time-varying electricity demand and accommodating the intermittency associated with wind and solar power.

Historically, because of its higher fuel price compared with nuclear, coal, and renewables, natural gas has typically had the highest marginal cost and has been dispatched after other generation sources. Consequently, natural gas has set the clearing price for electricity in much of the country. Lower natural gas prices, the opportunities created by abundant relatively low-cost supplies of unconventional shale gas, increased coal costs, and impending environmental regulations that will add to the cost of coal generation are, however, changing the role of gas in power generation.

The Emissions Prediction and Policy Analysis (EPPA) model employed in Chapter 3 is designed to study multi-sector, multi-region effects of alternative policy and technology assumptions, and as a result it only approximates the complexities of electric system dispatch. In this chapter, we analyze in greater depth two of the cases studied there, employing a more detailed model of the electric sector — MARKAL (see Box 4.1). This model is also used to further explore the implications of uncertainty in fuel and technology choices as they influence natural gas demand in this sector, extending the uncertainty analysis in Chapter 3 which considers only the uncertainty in gas resources.

**Table 4.1 2009 Average Capacity Factors by Select Energy Source, U.S. (numbers rounded)**

| Coal | Petroleum | Natural Gas CC | Natural Gas Other | Nuclear | Hydroelectric Conventional | Other Renewables | All Energy Sources |
|---|---|---|---|---|---|---|---|
| 64 | 8 | 42 | 10 | 90 | 40 | 34 | 45 |

Source: EIA, Table 5.2, Average Capacity Factors by Energy Source

This chapter then considers two questions about gas use in U.S. power generation: (1) What is the potential for reducing $CO_2$ by changing the current generation dispatch order[2] to favor NGCC over coal generation? (2) What will be the effect of increased penetration of wind and solar generation on natural gas power generation?

To answer the first question, it is important to understand NGCC utilization patterns. NGGC units are designed to be operated at capacity factors of up to around 85% rather than the current national average of 42%. This suggests possible opportunities for displacing some coal with gas generation, thereby lowering $CO_2$ emissions from the sector. We examine how much of this capacity could actually be applied to this purpose without diminishing system reliability. An important by-product of such a change, also analyzed, would be associated reductions in criteria pollutant emissions.

To explore the second question, the interaction between intermittent renewables and natural gas use is analyzed from two viewpoints: one in the *short term* when additional intermittent capacity is introduced into a system with other sources fixed; and the other in the *longer term* when the overall supply structure has time to adjust to growth in intermittent capacity. In this regard, we note that, at a more granular level than is presented in Table 4.1, wind turbines have an average capacity factor of 27%, solar thermal, 19%, and solar PV, 14%, and gas combustion turbines and steam turbines (used to balance load) have average capacity factors of 5% and 14%, respectively.[3]

Study of these two questions is approached with the use of two additional electric sector models, each designed to simulate the power system and its operations in detail over a range of conditions and timescales (see Box 4.1), enabling the following analyses:

- An examination of reliability and transmission constraints, which helps to isolate and understand the total generation required at points in time to meet demand for electricity and maintain operating reserve capacity and adequate installed capacity margins. We employ ReEDS for this analysis, which uses multiple time periods for any given year and reports results by geographic regions.

- An exploration of annual scenarios at the hourly level, which takes into consideration details of real-time problems, such as uncertainty and variability in demand and in generation patterns for intermittent technologies, and start-up and shut-down characteristics for plant cycling. Here we use the Memphis model.

## ELECTRICITY SYSTEM OVERVIEW

The electricity system is complex; this overview of how the system works, including the regimes under which power plants operate and the hierarchy of decision-making that influences the capacity and generation mixes, is intended to enhance the understanding of the implications of the modeling and analysis discussed later in the chapter.

Electricity is produced from diverse energy sources, varied technologies and at all scales. Sources for electric generation include a mix of renewables (sun, wind, hydro resources, among others), fossil fuels (oil, natural gas, coal), and uranium. As such, the generation of electricity comprises a variety of technologies with the type of fuel being used, and characterized by a wide range of investment and operating costs. Conventional power plants are operated under different regimes, mainly depending on their variable operating costs and operating flexibility.[4]

- *Baseload plants* are characterized by expensive capital costs and low variable costs, and they are operated most of the time during the year. They tend to be inflexible plants as they cannot easily change their operational level over a wide usage.

- *Peaking plants* are characterized by low capital costs and higher variable costs, and they are operated a few hours per year when the electric load is the highest. They can be characterized as flexible plants because of their quick operating response.

- *Intermediate plants* have variable costs that fall in between those of peaking and baseload technologies, and they are operated accordingly. They can be characterized as cycling plants, i.e., plants that operate at varying levels during the course of the day and perhaps shut down during nights and weekends.

The expansion planning and operation of electric power systems involve several decisions at different timescales, generally based on economic efficiency and system reliability criteria. This process has a hierarchical structure, where the solutions adopted at higher levels are passed on to the lower levels incorporating technical or operational restrictions at that level:[5]

- *Long-term* decisions are part of a multi-year process (3 years up to 10 or more years) that involves investments in generation and in the network required to expand the system.

- *Medium-term* decisions are taken once the expansion decisions have been made. They are part of an annual process (up to 3 years) that determines the generation unit and grid maintenance schedule, fuel procurement, and long-term hydro resource scheduling.

- *Short-term* decisions are a taken on a weekly time frame. They determine the hourly production of thermal and hydroelectric plants for each day of the week (or month), subject to availability of the plants and to hydro production quotas determined at the upper decision level, considering not only variable operating costs, but also the technology's own technical characteristics such as start-up and shut-down cost and conditions, a plant's technical minima, and ramping times. In addition, these short-term decisions are subject to generating reserve capacity needed to immediately respond to unexpected events.

- *Real-time* decisions involve the actual operation of the system (seconds to minutes). They involve the economic dispatch of generation units, the control of frequency so that production and demand are kept in balance at all times, while maintaining the system components within prescribed safe tolerances of voltages and power flows, accounting also for possible contingencies.

Finally, meeting reliably the consumption of electric power at all times requires having both adequate installed capacity and secure operation procedures. A reliable operation involves using ancillary services at different levels, maintaining sufficient capacity in reserve (quick-start units, spinning reserves) and with enough flexibility to respond to deviations in the forecast of demand or intermittent generation, and to unexpected events, such as the sudden loss of lines or generation plants.

## THE ROLE OF GAS GENERATION UNDER A $CO_2$ LIMIT

The EPPA model simulations in Chapter 3 provide insights into both the economy-wide use of natural gas and its market share in electric power under various assumptions about greenhouse gas (GHG) mitigation. Application of the MARKAL model, with its greater electric sector detail, provides a check on the adequacy of the EPPA approximations for the power sector. MARKAL considers a more complete listing of the generation alternatives, and it addresses the variation in the level of electricity demand, as a result of the diurnal, weekly, and seasonal cycles (which EPPA only roughly approximates). This variation is important because different technologies are needed to run different numbers of hours per year — a pattern that changes over years with demand growth and new investment. Also, the MARKAL model allows for a more complete exploration of uncertainty in gas use in the power sector.

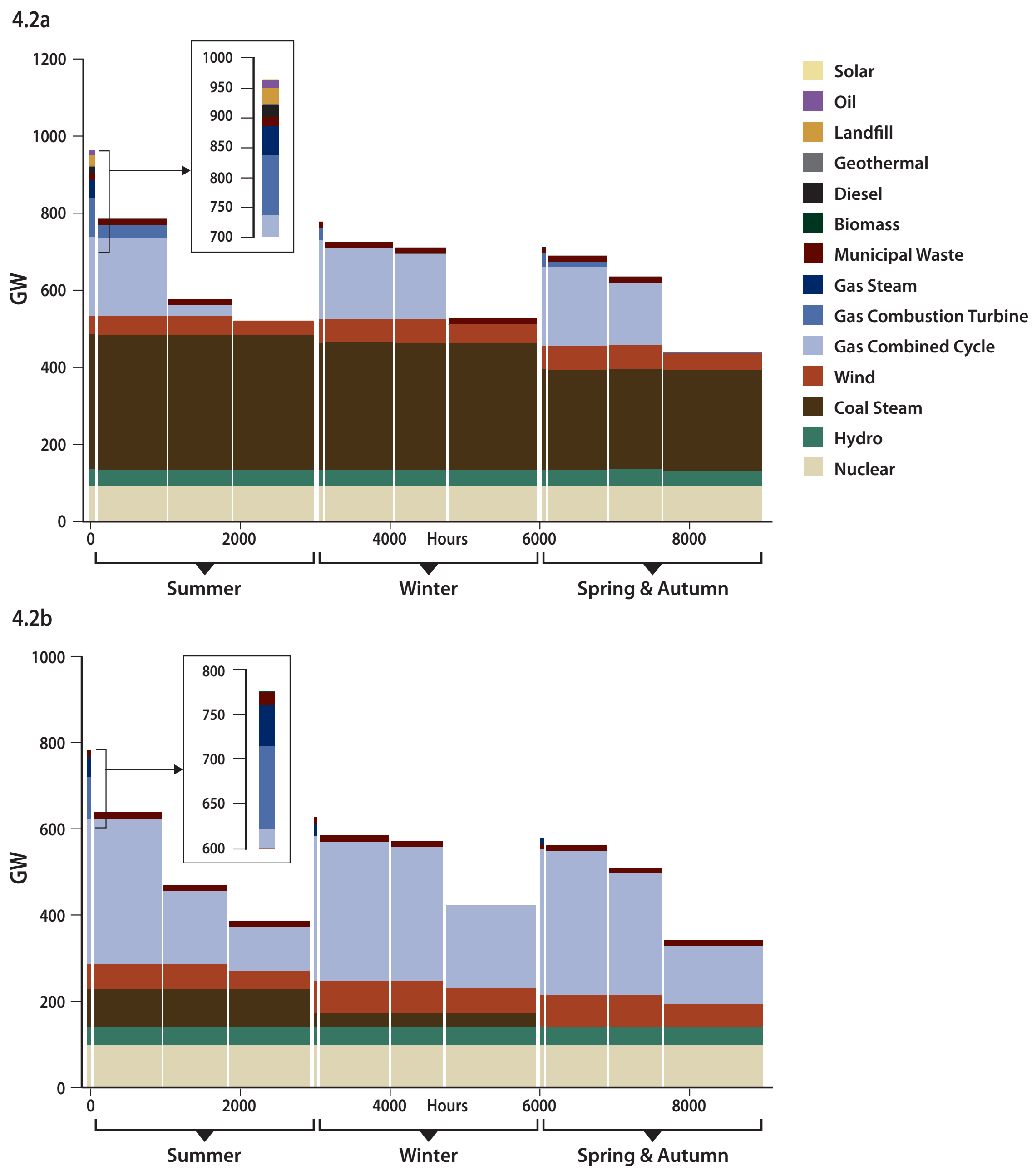
For consistency with the analysis in Chapter 3, certain MARKAL inputs are taken from the EPPA model results, including electricity demand, supply curves for natural gas and coal, and the reference costs of generation technologies. Also, two of the same policy cases are considered: Scenario A, which assumes no new GHG policy; and Scenario B, which imposes a Price-Based mitigation measure. For the Price-Based case, a cap on $CO_2$ emissions for the electric sector in MARKAL is set based on the results for that scenario in Chapter 3.

The underlying technology mix computed by the more-detailed electric sector model can be illustrated by annual load duration curves, which show the mix of generation dispatched at different times to meet changes in the level of electricity demand in the contiguous U.S. electric system over the course of a year. These curves for the year 2030, with and without a policy of carbon constraints, are shown in Figure 4.2. In the absence of a carbon policy (Panel a), generation from hydro, coal, and nuclear occur at all times of the year while generation from wind and hydro are supplied whenever they are available.[6]

Without a carbon policy (Panel a), natural gas generation from combined cycle and steam turbines occurs for less than half of the time over the course of the year during periods of higher demand; and natural gas combustion turbines are used for only a few hours per year at the peak demand hours.

Under the carbon price policy (Panel b), Natural Gas Combined Cycle (NGCC) technology largely substitutes for coal to provide baseload generation along with nuclear generation.

**Figure 4.2 Time Blocks Approximation to the Load Duration Curve for the (a) No Policy and (b) 50% Carbon Reduction Policy Scenarios in 2030. Three seasons have been considered: summer, winter, and spring/autumn. Within each season, there are four blocks: peak time, daytime PM, daytime AM, and nighttime, as shown in the graphs. The peak time block is very narrow.**



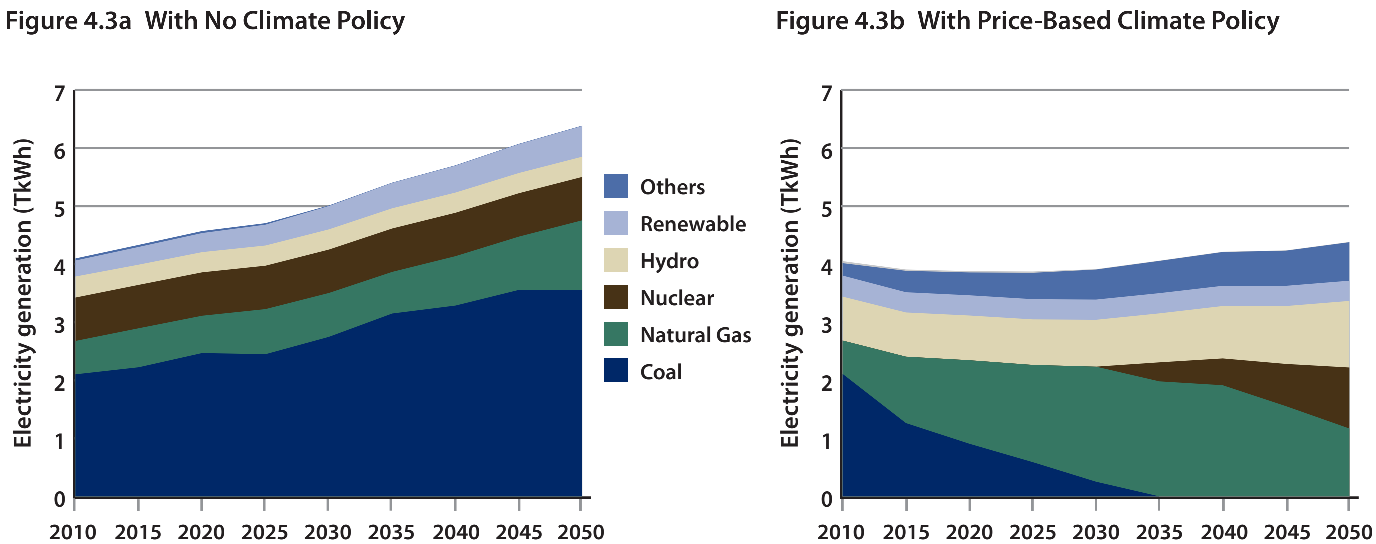

Source: MIT analysis

The change over time in the energy mix in the electric sector is shown in Figure 4.3 for both the No Policy and the Price-Based cases. In the No Policy case, under reference assumptions for fuel prices, electricity demand, and technology costs — and mean gas resources — these results show the same pattern of increasing gas use as the simulation studies in Chapter 3. The gas use in this sector in 2025 is essentially the same in the two studies. Toward the end of the simulation period, MARKAL projects one-quarter to one-third more gas-based generation than EPPA, though gas generation is still small relative to coal.

Under the Price-Based policy, the overall pattern of change remains the same as in EPPA: coal is forced out and replaced by gas. In the period to 2025, MARKAL projects a more rapid phase-out of coal than does EPPA, in part because MARKAL is a forward-looking model and sees higher prices in the future whereas the recursive dynamic (myopic) EPPA model does not. Farther out in time coal is no longer in the mix, and under a continuously tightening $CO_2$ constraint, conventional gas generation begins to be replaced by non-carbon generation sources such as nuclear, renewables, and/or coal or gas with carbon capture and storage (CCS).

The EPPA model expands nuclear generation whereas MARKAL introduces natural gas with CCS, yielding about a one-quarter greater level of gas use. The outlook for gas in this sector is consistently positive across the two studies, and the difference in details of load dispatch is to be expected for models of such different mathematical structure, and well below the level of uncertainty in either (see Figure 4.3).

**Figure 4.3 Future Energy Mix in Electricity Sector**




Source: MIT Analysis

The systems studies in Chapter 3 consider only uncertainty in the estimates of gas resources (Figures 3.2, 3.3, and 3.0). Applying the MARKAL model and the reference assumptions discussed above, a study was carried out of the effect on gas use of uncertainties not only in resources but in other prices, electricity demand, and technology costs. The same two cases were considered: No Policy and the Price-Based policy. Here we describe results for a 50% confidence interval: i.e., a 25% chance of gas use above the high level as shown, and a 25% chance of use below the low level. Details of the analysis are provided in Appendix 4B.

By 2030, with no additional mitigation policy, the gas demand by the electric sector runs 17% above and 19% below the mean value of 6.3 trillion square feet (Tcf) (50% confidence interval). The main factors leading to this range are the demand for electricity, the prices of natural gas and coal and the costs of new technologies, in particular the cost of new coal steam and Integrated Gasification Combined Cycle (IGCC) technologies.

Under the Price-Based policy the uncertainty is substantially greater, ranging from 47% above to 42% below the mean value of 12.8 Tcf (50% confidence interval). The main influence behind this greater uncertainty is in the costs of technologies that might substitute at large scale for fossil-based generation, such as wind, solar, and advanced nuclear generation technologies. The share of natural gas in the generation mix is a result of the interplay between technologies that both compete with and complement each other at the same time as they supply different segments of demand over the year.

The uncertainty ranges given here are intended to caution the reader against giving too much weight to the actual numbers in future projections in this chapter and elsewhere in the report. Rather, the critical insights are about the trends and relationships, which are more robust across a wide range of possible futures.

## NEAR-TERM OPPORTUNITIES FOR REDUCING $CO_2$ EMISSIONS BY ENVIRONMENTAL DISPATCH

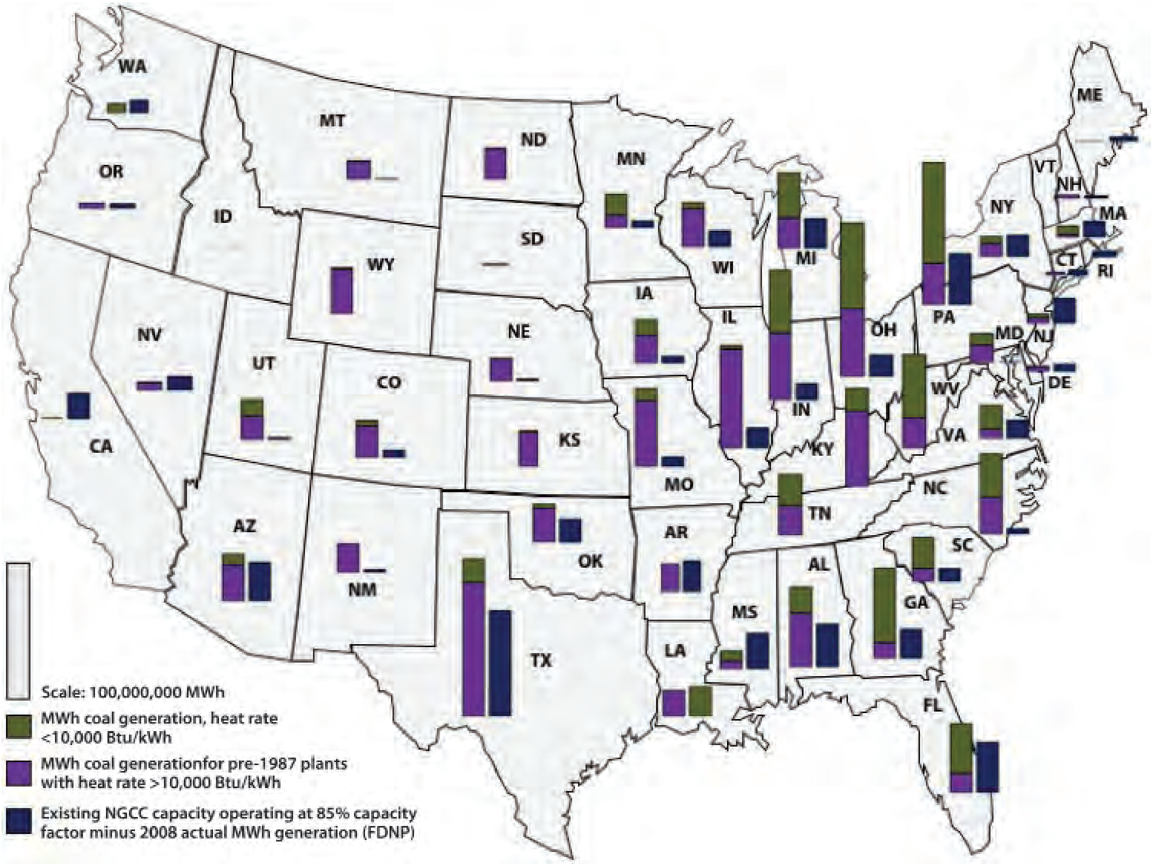
Near-term opportunities for $CO_2$ emission reductions in the power sector are limited by the current generation mix and transmission infrastructure, the cost of renewables and other low-emission sources and technologies, as well as the lag times associated with siting and building any new generation capacity. The re-ordering of generation between coal and gas units (modeled here as a form of environmental dispatch forced by a $CO_2$ constraint[7]) may be the only option for large-scale $CO_2$ emissions reduction from the power sector which is both currently available and relatively inexpensive.

As noted, the current fleet of NGCC units has an average capacity factor of 41%, relative to a design performance of approximately 85%. An electric system requires capacity to meet peak demands occurring only a few hours per year, plus an operating reserve, so the system always includes some generation units that run at capacity factors below their design value. However, the U.S. has enough spare capacity in other technologies to allow dispatching more NGCC generation, displacing coal and reducing $CO_2$ emissions, without major capital investment. An additional benefit of this approach would be to substantially reduce emissions of air pollutants such as sulfur dioxide ($SO_2$), nitrogen oxide (NOx), mercury (Hg), and particulates.

### NGCC Potential if Fully Dispatched

Figure 4.4 suggests the scale and location of the potential for shifting among generation units. Plotted there is the geographic distribution of fully dispatched NGCC potential (FDNP), defined as the difference between the electricity that would be produced by NGCC plants at an 85% capacity factor and their actual 2008 generation. Figure 4.4 also shows the geographic distribution of coal generation, divided into

**Figure 4.4 Scale and Location of Fully Dispatched NGCC Potential (FDNP) and Coal Generation (MWh, 2008)**




Source: USREP, MIT

less and more efficient units where a "less efficient" unit is defined as one with a heat rate over 10,000 Btu/kWh.

In many regions, FDNP generation matches well with less efficient coal capacity, suggesting opportunities for displacing emissions-intensive units, while other locations show few such opportunities. For example, Southeastern states such as Texas, Louisiana, Mississippi, Alabama, and Florida appear to have relatively larger opportunities, while those in Midwestern states such as Illinois, Indiana, and Ohio are relatively smaller.

### Possible Contribution of NGCC Capacity to a $CO_2$ Reduction Goal

Figure 4.4 represents only the average potential available over the course of the year, aggregated by state, therefore providing an upper limit of the substitution potential; it does not equate to "surplus" generation capacity. For this discussion, *"surplus" is defined as the amount of NGCC generation that can be used over the course of one year to replace coal while respecting transmission limits, operation constraints, and demand levels at any given time.*

To account for a number of system characteristics that may better identify the range of opportunities for fuel substitution, we apply the ReEDS model (see Box 4.1). This model is well suited for examination of reliability and transmission constraints, demand fluctuations, and reserve capacity margins that will limit these opportunities. Also, as noted, ReEDS reports results by geographic regions.[8]

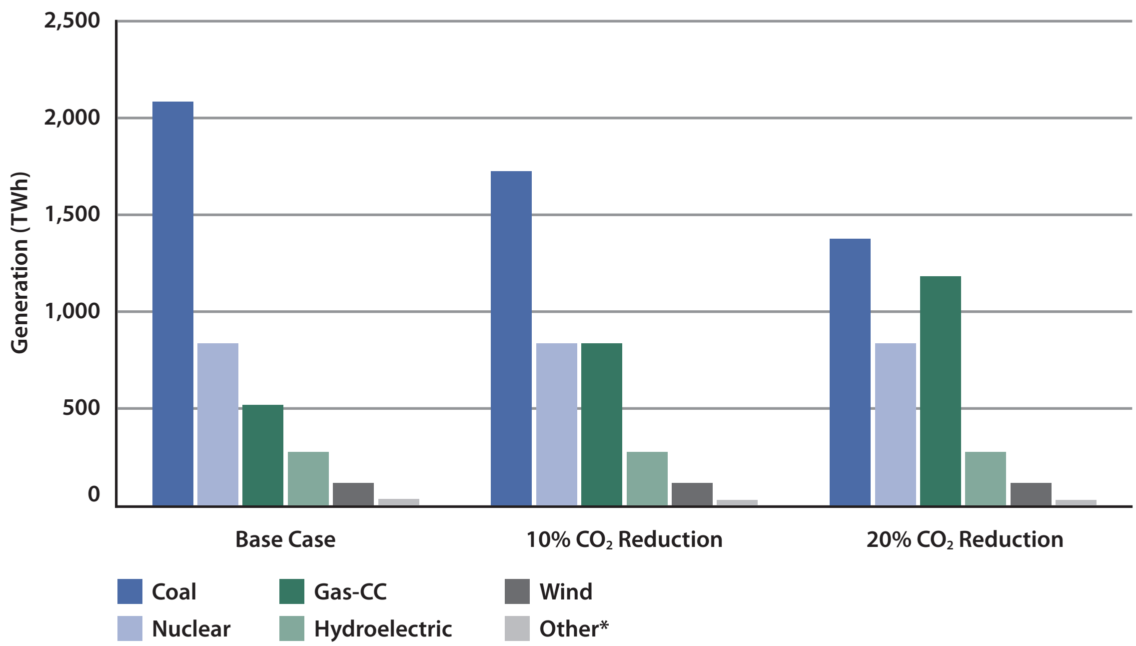
This enables us to identify opportunities to change the fuel dispatch order nationwide, and provides insights into five regions of the country: the Electric Reliability Council of Texas (ERCOT), Midwest Independent Transmission Operator (MISO), Pennsylvania-New Jersey-Maryland (PJM), New England (ISO-NE), and Florida Reliability Coordinating Council (FRCC). Each region has different generation costs, fuel mixes, and ability to trade electricity:

- ERCOT is essentially electrically isolated from the rest of the country;
- MISO and PJM are heavily interconnected; they import and export electricity from each other, but have a relatively small amount of NGCC surplus;
- ISO-NE and FRCC have surplus NGCC but New England has relatively little coal generation, whereas Florida has a significant percentage of inefficient coal capacity that might be a candidate for displacement.

We analyze the potential for a version of environmental dispatch by running the ReEDS model for the year 2012 in three scenarios: $CO_2$ unconstrained, a 10% reduction in U.S. electric sector $CO_2$ emissions, and a 20% reduction. Runs for the year 2012 are used because the model does not invest in new capacity in this time period; as such, $CO_2$ reductions are attributable to the shift of generation among existing units.

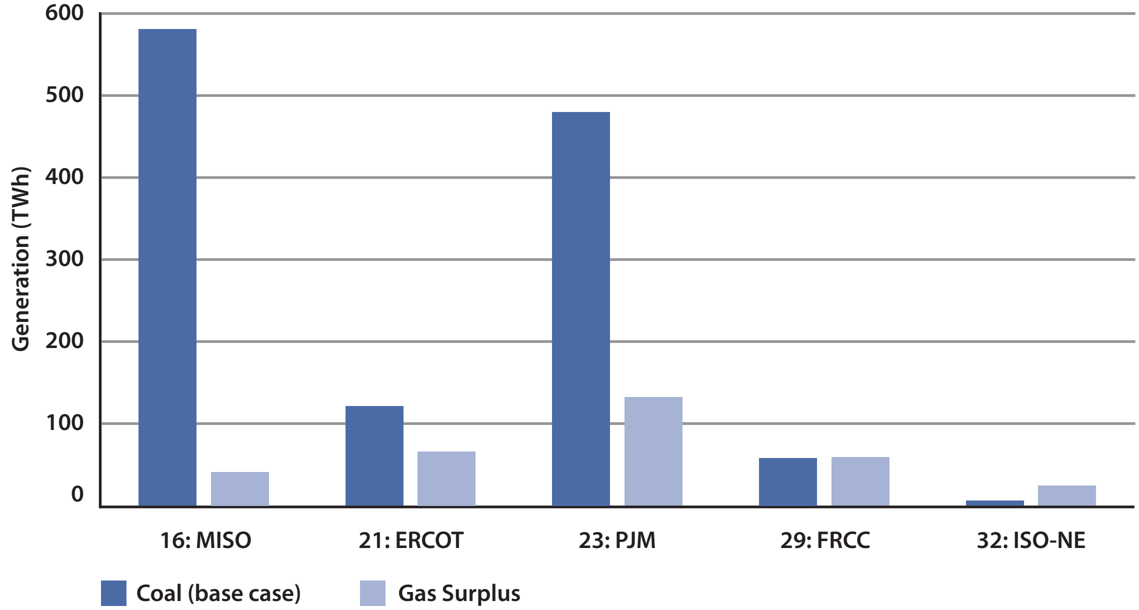
Figure 4.5 illustrates the changes in generation by technology under the three scenarios. In the 20% $CO_2$ reduction scenario, the NGCC fleet has an average capacity factor of 87%, displaces

**Figure 4.5 Generation by Technology under Various $CO_2$ Constraints, U.S.[9], 2012**




Source: MIT Analysis

**Figure 4.6 NGCC and Coal Generation in Select Regions under a 20% $CO_2$ Constraint, U.S., 2012**




Source: MIT Analysis

about one-third of 2012 coal generation (700 terawatt-hours (TWh)), and increases gas consumption by 4 Tcf.[9]

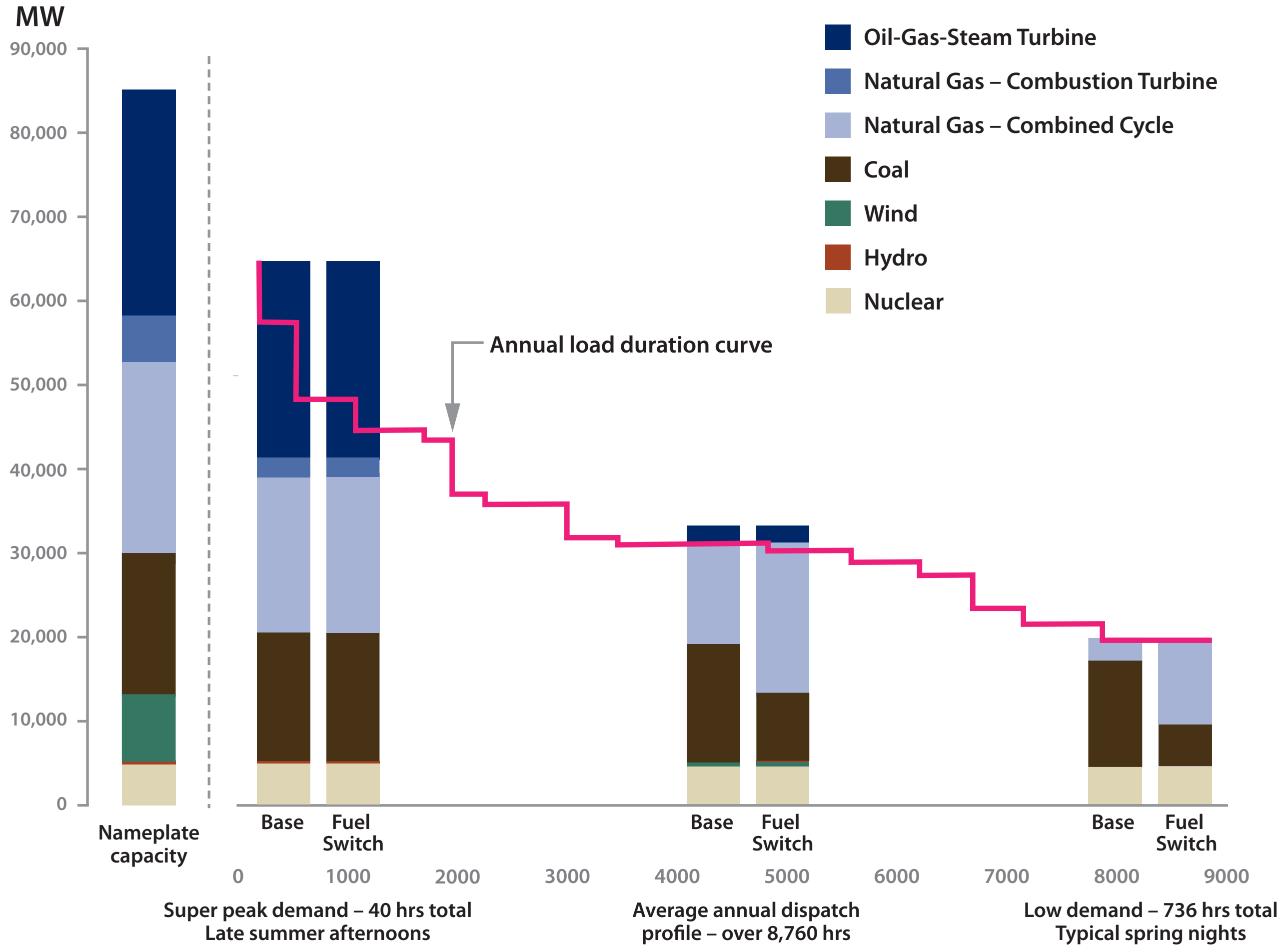
In Figure 4.5, as the carbon constraint increases, most of the electricity generation by technology does not change. Coal and natural gas are the exceptions: as the carbon constraint increases, coal generation significantly declines, and NGCC proportionally increases.

Although NGCC displacement of coal generation is nearly one-for-one at the national level, the change in generation and emissions is not uniform across regions. Figure 4.6 shows regional results, comparing coal generation in the absence of a $CO_2$ target to surplus NGCC generation in a 20% reduction scenario.

In Figure 4.6, the left bars represent the amount of regional coal generation absent carbon constraints, using ReEDS 2012 forecasts. This is the "business as usual" scenario. The right bars represent the amount of additional NGCC generation that is available for dispatch in the current system after satisfying all system requirements. This additional amount of generation is calculated as the difference between the NGCC generation dispatched in the base case and in the 20% $CO_2$ reduction scenario. The largest potential for substitution of NGCC for coal generation is in PJM, although in both PJM and MISO coal continues to dominate.

A closer look at how the imposition of a $CO_2$ limit would shift generation among units can be seen in the revised unit dispatch at different *demand* levels. For this analysis, we look at ERCOT, a system that is isolated from the rest of the U.S. and, in our re-dispatch scenarios, has regional percentage of $CO_2$ reductions that tracks national reductions. Because of these similarities to the country, and because of the greater availability of operations information from ERCOT, an analysis of ERCOT, using

**Figure 4.7 Changes in Dispatch Order to Meet ERCOT's 2012 Demand Profile, with and without a 20% $CO_2$ Constraint**




Source: MIT Analysis

ReEDS provides additional details about fuel switching on a more granular timescale.

Figure 4.7 illustrates how existing capacity would be dispatched to meet 2012 projected demand for the highest peak, average, and low demand situations, with and without the $CO_2$ target to force a change in unit dispatch.[10] The figure shows an unconstrained base case and a case with a 20% $CO_2$ reduction. The average profile shows the generation dispatch for all technologies across an entire year (8,760 hours), not a single time slice.

In Figure 4.7, the red line represents 17 time periods of demand for the year, sorted from greatest to least demand. The bar graphs to the right of the nameplate capacity bar show the dispatch profile in those time periods under two carbon scenarios: no reduction and 20% reduction.

Not surprisingly, the results indicate that the greatest opportunities for displacement of coal generation exist during average and low demand periods. Figure 4.7 also shows that coal generation is dispatched in every time period, indicating that not enough NGCC surplus exists in ERCOT to completely displace coal;

**Table 4.2 National Emissions for $CO_2$-Reduction Scenarios**

| | Base Case | Case 1 – 10% $CO_2$ Reduction | Case 2 – 20% $CO_2$ Reduction | % Reduction from Base Case for Case 1 | % Reduction from Base Case for Case 2 |
|---|---|---|---|---|---|
| $CO_2$ (million metric tons) | 2,100 | 1,890 | 1,680 | | |
| $SO_2$ (million tons) | 5.66 | 5.66 | 5.46 | — | 4% |
| NOx (million tons) | 4.66 | 3.92 | 3.16 | 16% | 32% |
| Hg (tons) | 48 | 40 | 32 | 17% | 33% |

Source: MIT analysis

conversely, surplus NGCC capacity exists and can displace some coal capacity in *all* demand periods examined, even during the super peak, although the amount is small.

## Effect of System Re-Dispatch on Criteria Pollutants

The Clean Air Act (CAA) requires power plant controls on $SO_2$, NOx, particulates, and Hg. According to the EPA, "60% of the uncontrolled power plant units are 31 years or older, [some] lack advanced controls for $SO_2$ and NOx, and approximately 100 gigawatts (GW) out of total of [more than 300] GW of coal are without $SO_2$ scrubbers."[11]

Table 4.2 contains results from ReEDS under the three scenarios that indicate the potential effects of the $CO_2$ constraint (also shown) on emissions of $SO_2$, NOx, and Hg. (The model does not project particulate emissions, which also would be reduced.) While ReEDS does not fully model the trading markets for $SO_2$ and NOx, it makes a reasonable approximation by capping national emissions levels and making economically efficient dispatch decisions under these constraints. In all three simulations the cap for $SO_2$ emissions is based on the 2005 Clean Air Interstate Rule (CAIR) interpolated for 2012.[12]

Changes to the dispatch order of generation, from coal to gas, would lower prices in the $SO_2$ market, and might even yield a reduction in national emissions below the CAIR limit, as shown with a 4% change in Case 2. Importantly, the reductions in NOx and Hg emissions could be substantial, by as much as one-third under the more stringent $CO_2$ limit.

Table 4.3 shows the corresponding emissions profiles by region for $CO_2$ and Hg. (ReEDS does not provide adequate regional detail for $SO_2$ and NOx). Each region acts in its own best economic interests under the given constraints. And, because of variation in generation costs, installed capacity, and transmission differences between regions, some regions have comparative advantage dispatching less $CO_2$-intensive generation. Depending on the regulatory structure, regions with these advantages may produce more electricity, export it, and/or sell credits (assuming a cap-and-trade approach); and regions which typically deploy technologies that are more $CO_2$ intensive take opposite actions. This leads to uneven emissions effects on individual regions.

A 20% emissions reduction in electric sector $CO_2$ emissions through coal-to-gas displacement would represent mitigation of 8% of the U.S. total. The ReEDS model does not provide

**Table 4.3 Emissions of Select Regions Before and After Re-Dispatch, 2012**

| Base Case | MISO | ERCOT | PJM | FRCC | ISO-NE |
|---|---|---|---|---|---|
| $CO_2$ (million metric tons) | 543 | 153 | 446 | 67.2 | 19 |
| Hg (tons) | 13.4 | 2.77 | 11 | 1.32 | 0.138 |
| | | | | | |
| **Case 2 – 20% $CO_2$ Reduction** | | | | | |
| $CO_2$ (million metric tons) | 394 | 121 | 351 | 78.9 | 25.4 |
| Hg (tons) | 9.30 | 1.43 | 7.58 | 1.13 | 0.10 |
| % Hg reduction | 31% | 48% | 31% | 14% | 27% |

Source: MIT Analysis

*There is sufficient surplus NGCC capacity to displace roughly one-third of U.S. coal generation, reducing $CO_2$ emissions from the power sector by 20% and yielding a major contribution to control of criteria pollutants. This would require an incremental 4 Tcf per year of natural gas, which corresponds to a cost of \$16 per ton of $CO_2$.*

an accurate estimate of the national economic cost of this option, but an approximation can be made by comparing the break-even $CO_2$ price at which the cost of NGCC generation equals the cost of coal generation, given their different variable operations and maintenance costs, heat rates, and $CO_2$ emissions rates.[13] The result is an implicit cost of about \$16 per ton $CO_2$.

More analysis is required to determine whether, because of the geographic differences between NGCC and coal units, some new transmission infrastructure may be necessary. Nonetheless, a more complete analysis is very likely to prove the cost of this option to be low compared to most other mitigation options. For example, one estimate of the per-ton $CO_2$ emissions avoidance cost estimate to retrofit a typical sub-critical coal plant with post-combustion CSS is \$74 per ton.[14]

It should also be noted that coal-to-gas fuel switching is already occurring. According to the Energy Information Agency (EIA), "The increase in delivered coal prices and the decrease in delivered natural gas prices, combined with surplus capacity at highly efficient gas-fired combined-cycle plants resulted in coal-to-gas fuel switching. Nationwide, coal-fired electric power generation declined 11.6 percent from 2008 to 2009, bringing coal's share of the electricity power output to 44.5 percent, the lowest level since 1978."[15]

In sum, there is sufficient surplus NGCC capacity to displace roughly one-third of U.S. coal generation, reducing $CO_2$ emissions from the power sector by 20% and yielding a major contribution to the control of criteria pollutants. This would require an incremental 4 Tcf per year of natural gas, which corresponds to a cost of \$16 per ton of $CO_2$. Currently there is no national price on $CO_2$, but there are both regional programs and Federal regulatory activities underway.

**RECOMMENDATION**

**The displacement of coal generation with NGCC generation should be pursued as the most practical near-term option for significantly reducing $CO_2$ emissions from power generation.**

## INTERMITTENT RENEWABLE ELECTRICITY SOURCES AND NATURAL GAS DEMAND

In this section, we explore the impacts of the introduction of significant amounts of intermittent wind and solar electricity generation on natural gas generation and overall natural gas demand.

This analysis first explores the *short-term effects* of intermittent wind and solar generation on gas generation and demand, a scenario which assumes that the capacity from technologies — other than wind or solar — is fixed. Some European countries already approximate this situation, where substantial volumes of wind or solar generation have been installed during the last few years. Also in some U.S. states, the proportion of intermittent generation exceeds 10% and the dispatch of existing conventional generation units has had to adjust accordingly.

We then turn to *longer-term impacts*, where the deployment of intermittent generation is assumed to take place gradually, possibly in response to government policies that, for example, set a mandatory target for renewable generation. Over time, capacity additions and retirements of other technologies are made as the system adjusts to intermittent generation.

### Effects in the Short Term

To elucidate the *short-term effects*, we use:

- a 2030 projected generation portfolio as the base case, obtained from the ReEDS $CO_2$ Price-Based policy scenario (see Box 4.1); and
- the Memphis model (see Box 4.1) applied to *daily dispatch patterns* for ERCOT which, as noted earlier, is an isolated system that can be studied without the complicating influence of inter-regional transmission.

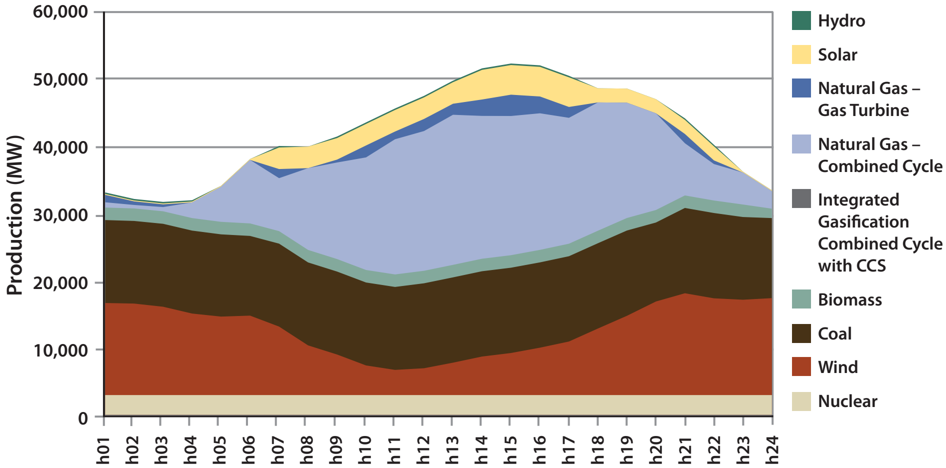
With this 2030 generation portfolio as our reference point, we examine the daily dispatch patterns of all generation technologies, including natural gas, when greater or lesser levels of wind or solar electricity generation are made available to be dispatched and the capacities of the other technologies are held constant.

**Wind generation.** The results for varying levels of wind generation are seen in:

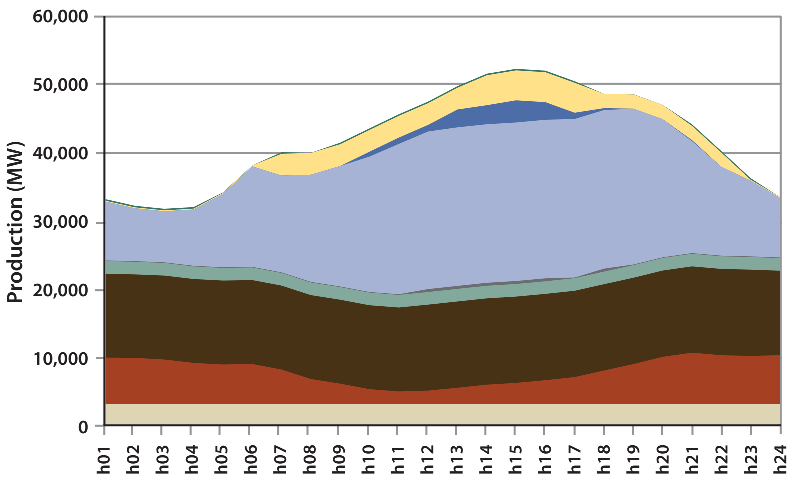
- Figure 4.8a, the base case, which is a *representative day* for ERCOT;
- Figure 4.8b, when wind produces *half the amount* of generation as in the base case; and
- Figure 4.8c, where wind produces *twice the amount* of generation as in the base case.

## Figure 4.8 Impact of Wind on a One-Day Dispatch Pattern for ERCOT

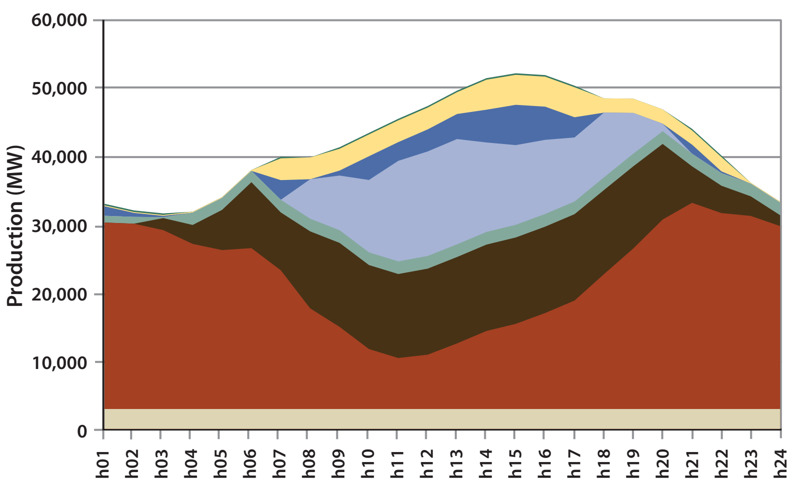
### 4.8a Wind Base Case




### 4.8b Wind 0.5




### 4.8c Wind 2.0




Source: MIT Analysis

In Figure 4.8a, the base case depicts the estimated *existing* contribution from wind in ERCOT in 2030. The nighttime load (roughly hours 01 through 04) is met by nuclear and coal baseload plus wind generation. There is no appreciable output from gas between hours 01 and 04 because it has higher variable costs than nuclear and coal and it gets dispatched last. Natural gas also has the flexibility to cycle. In hours 05 through 23, when overall demand increases during the early morning and decreases in the late evening, NGCC generation adjusts to match the differences in demand.

As depicted in Panel 4.8b, when less wind is dispatched, the NGCC capacity is more fully employed to meet the demand, and the cycling of these plants is significantly reduced. The baseload plants continue to generate at full capacity.

In Panel 4.8c with twice as much wind as the base case, natural gas generation is reduced significantly; the gas capacity that is actually used is forced to cycle completely. Baseload coal plants are also forced to cycle because of the relatively low nighttime demand; coal plant cycling can increase $CO_2$, $SO_2$, and NOx emissions.[16]

**Solar Generation.** Like wind, for solar there are figures depicting: a base case in ERCOT (Figure 4.9a); a case where solar provides *half the amount* of generation as the base case (Figure 4.9b); and a case where solar provides *twice* the generation seen in the base case (Figure 4.9c).

The pattern with solar is somewhat different than for wind. The solar generation output basically coincides with the period of high demand, roughly between hours 06 and 22. As seen in the base case Figure 4.9a, this is also when NGCC capacity gets dispatched. The natural gas plants are used more when solar output is less (see Figure 4.9b). Conversely, when solar is used more, less gas is dispatched (see Figure 4.9c).

The baseload plants are largely unaffected and cycling is not a problem for them, since there is no intermittent solar-based generation during the low-demand night hours.

In sum, our short-term analysis shows that the most significant impacts of a quick deployment of additional wind or solar at any given future year will most likely be both a reduction in production from, and an increase in cycling of, gas-fueled NGCC plants; there is a less significant fall in production for the much-less-employed, single-cycle gas turbines and steam gas units.

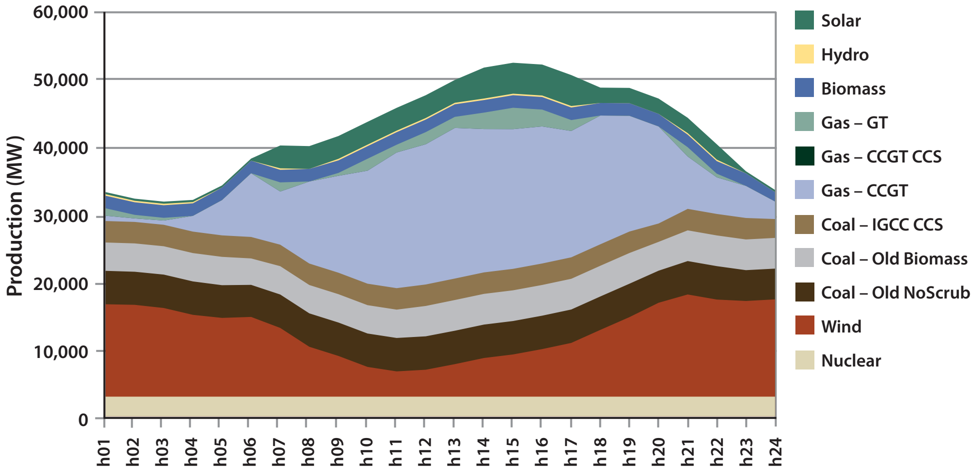
*[In the short term]….the most significant impacts of a quick deployment of additional wind or solar … will most likely be both a reduction in production from, and an increase in cycling of, gas-fueled NGCC plants….*

The displacement of gas is greater for solar than for wind, since solar production has a stronger correlation with demand than does wind generation.

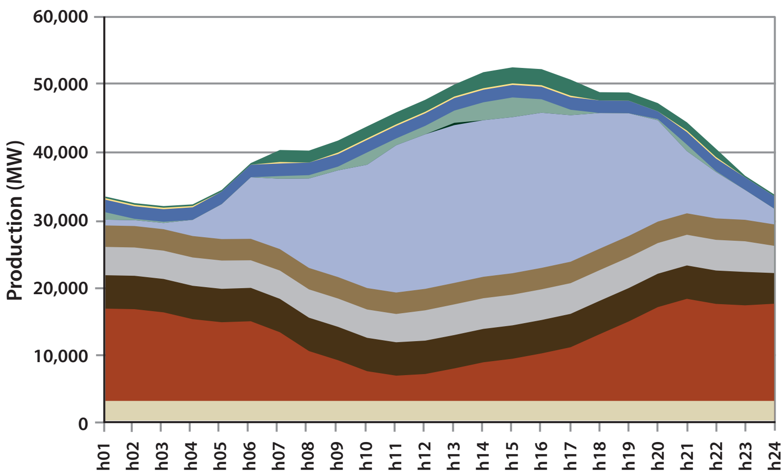
Large wind penetrations may also displace some coal production and result in some cycling of these plants. No impact on nuclear production is expected with the average U.S. technology mix.

## Figure 4.9 Impact of Solar CSP (No Storage) on a One-Day Dispatch Pattern for ERCOT

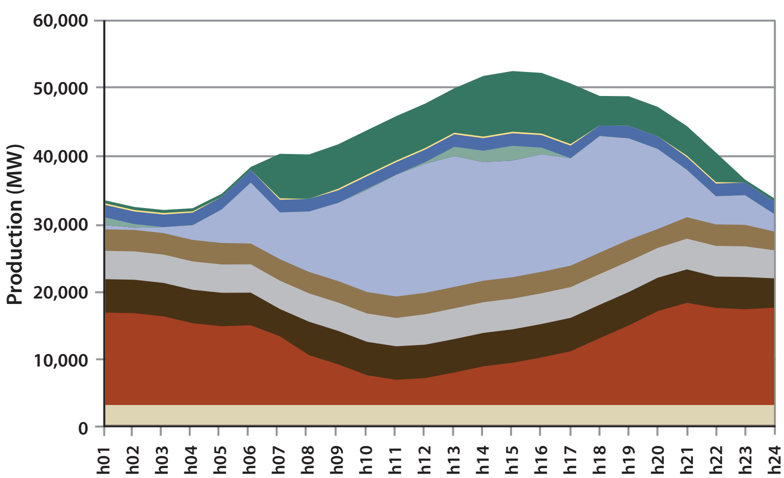
### 4.9a Solar Base Case




### 4.9b Solar Base Case x 0.5




### 4.9c Solar Base Case x 2.0




Source: MIT Analysis

## Effects in the Long Term

To explore the effects of the penetration of intermittent generation over the *long term*, we examine two policy scenarios, both with a system expansion to 2050 and a target leading to a 70% reduction of $CO_2$ emissions in the U.S. power sector.

We look at two different versions of the 70% reduction case because the means by which the target is implemented — through different mitigation policy instruments — has an effect on how the system responds to more or less expensive renewable generation. The two policy instruments we examine are:

- the imposition of a *$CO_2$ price* to achieve the $CO_2$ emissions reduction target; and
- the imposition of an *emissions constraint* to achieve the same target.

We then analyze how the electric system, and gas use over time, would differ if the capital costs of solar or wind generation capacity were higher or lower than the reference levels for the two base cases. Again the ReEDS model is employed.[17]

In the ReEDs simulations of both policy scenarios, the generation mix evolves over time, similar to that shown in Chapter 3, Figures 3.4a and 3.4b. During the early-to-middle decades of the simulation period the dominant event is the substitution of coal generation by NGCC units. At the same time, wind generators, with gas turbine back-up, begin to be deployed as a baseload technology.[18]

This combination of wind production and flexible generation capacity competes with potential new nuclear capacity and also erodes NGCC production. Wind impacts the preferred new baseload generation technology, the one that is most economic but for which expansion is not subject to environmental or other limits. Late in the period, conventional coal production has been replaced, economically competitive, wind resources start becoming exhausted, and nuclear plus some solar penetration begins.

**$CO_2$ Price-Based Case.** In the $CO_2$ Price-Based case, the nature of the system adjustments in these simulations can be illustrated using an example of the changes that would be brought about by *lower-cost wind* capacity. First, the increased intermittent renewable generation needs to be accompanied by flexible back-up capacity, albeit with low utilization levels. In the U.S., spare capacity of gas-fueled plants is enough to meet this requirement initially, but eventually additional investment is needed (gas turbines in these scenarios).

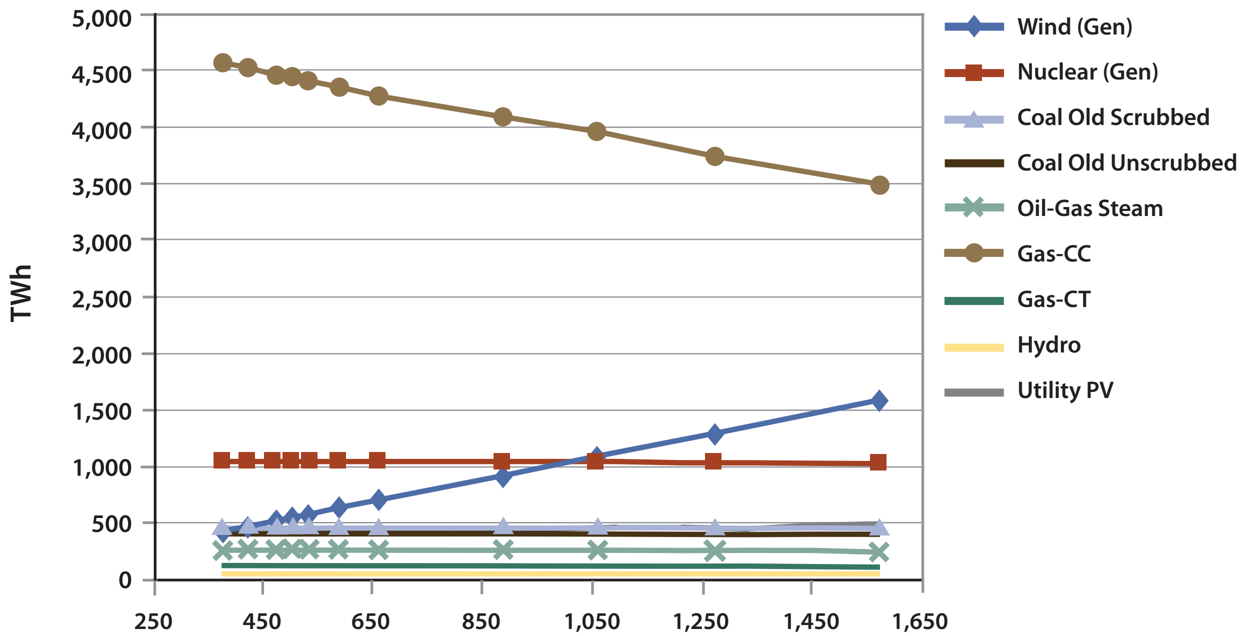
As this combination of new intermittent renewable and flexible electricity plants grows, it starts to replace the expansion and utilization of baseload generation technologies, nuclear or fossil generation with CCS (coal without CCS has already been forced out of the system by its $CO_2$ emissions). However, these classic baseload technologies are not increasing; therefore, the low-cost renewable capacity plus flexible generation increases in baseload and even in mid-merit service, at the expense of gas generation.

This interaction can be illustrated with a summary of what happens in the base case system for the ERCOT region when different renewable costs are simulated, therefore changing the intermittent generation penetration levels.

The results in Figure 4.10 are plotted to highlight the way cumulative gas generation changes with different assumptions about wind-generation costs and the corresponding wind-generation levels. The figure shows the total generation in TWh by type of generation technology over the simulation period from 2005 to 2050 and assumes the underlying emissions target is imposed by a $CO_2$ price. It illustrates that the displacement of gas by wind takes place through changed patterns of investment and generation over many years.

As Figure 4.10 shows, increased cumulative wind generation, as a consequence of lower wind investment costs, or an aggressive renewable portfolio standard, has a direct impact on the new investment and associated production by natural gas, equal to almost one TWh of reduced natural gas generation for one TWh of wind output. This happens because NGCC is the technology that is most vulnerable to wind competition, both before and after coal has been driven out of the market. It should also be noted that, while the cumulative generation of gas turbines (Gas-CT in Figure 4.10) does not change enough to show in the graph, gas turbine capacity actually increases substantially to support the additional wind contribution.

**Figure 4.10 Cumulative Generation in ERCOT in the Period 2005–2050 for All Technologies Given Alternative Levels of Wind Penetration (TWh)**




Source: MIT Analysis

In Figure 4.10, the horizontal axis is cumulative wind output, the vertical axis is the cumulative output for all technologies, including wind (if the two axes were plotted to the same scale, the function for wind would be a 45° line). The base-case level of wind generation is indicated with a vertical line, so that output to the right of that point results from lower capital costs and the output to the left results from higher capital costs.

Figure 4.10 also shows that the difference in cumulative generation by the other technologies is not much affected by changes in the contribution of wind generation. It should be repeated that this is a result for ERCOT. The differences in generation mix in other regions will vary, though viewed at the national level the pattern is very similar to that shown here.[19]

**$CO_2$ Cap Case.** The result differs somewhat if emissions mitigation is accomplished by a $CO_2$ cap instead of a price. The fixed $CO_2$ constraint implies that an increment in wind output that displaces NGCC production and investment also reduces the need for other low-$CO_2$ baseload capacity to reduce the emissions.

Cheaper wind creates slack under the emissions constraint, which may be filled by whatever is the cheapest generation source. In some simulations, this cheap generation comes from otherwise almost-idle coal-fired plants. Thus, as a minor perverse effect, under the $CO_2$ constraint more wind can imply a small increment of additional coal production — a condition that does not occur when coal is burdened by a $CO_2$ price.

The case of solar generation without storage is similar to wind in many respects. However, since the production profile of solar has a high level of coincidence with the daily demand and has a more stable pattern, an increment in solar generation does not require back-up from flexible gas plants as much as wind does. In fact, solar can partially fulfill a peaking plant role.

In summary, our analysis of gradual and sustained "long-term" penetration of wind and solar shows that large-scale penetration of wind generation, when associated to flexible natural gas plants, will assume a mostly baseload role, and will reduce the need for other competing technologies such as nuclear, coal, or even gas-fueled combined cycles, if expansion with coal and nuclear technologies does not take place because of economic, environmental, or any other reasons. This effect is less pronounced in the case of the solar technology, because of its characteristic daily production pattern.

*Our analysis shows that a gradual and sustained "long-term" substantial penetration of wind, when associated with flexible natural gas plants, will assume a mostly baseload role, and will reduce the need for other competing technologies such as nuclear, coal, or even gas-fueled combined cycles. This effect is less pronounced in the case of solar.*

Although our analysis has been limited to a few alternative scenarios, we can observe a consistent pattern for the impact of intermittent renewable generation: We see that an increase of wind or solar output systematically results in a proportionally significant reduction of natural gas fueled production, while, at the same time, the total installed capacity of flexible generation (typically also natural gas fueled plants) is maintained or increased.

Precise numerical estimations and any second order impacts are heavily dependent on the specific energy policy instruments and the assumptions on the future costs of fuels and technologies.

The detailed operational analysis of plausible future scenarios with large presence of wind and solar generation reveals the increased need for natural gas capacity (notable for its cycling capability and lower capital cost) to provide reserve capacity margins. This does not however necessarily translate into a sizeable utilization of these gas plants.

### Additional Implications

In deregulated wholesale markets with substantial penetration of renewables, the volatility of marginal prices can be expected to increase. Also, mid-range technologies, of which NGCC is the most likely candidate, will see their output reduced. The uncertainty regarding the adequate technology mix and the economics of such a mix under the anticipated future prices and operating conditions raise concern about attracting sufficient investment in gas-fueled plants under a competitive market regime.

This issue is presently being addressed by several European countries with significant penetration of wind generation, where the patterns of production of NGCC and single cycle gas turbines and also of some baseload technologies have already had major impacts. Similar situations are developing in some parts of the U.S. Presently there is no consensus on a suitable regulatory response to this situation, which could include enhancements of any capacity mechanisms such as those already in place in most U.S. wholesale markets, new categories of remunerated ancillary services, or other instruments.

**RECOMMENDATION**

**In the event of a significant penetration of intermittent renewable production in the generation technology mix, policy and regulatory measures should be developed to facilitate adequate levels of investment in natural gas generation capacity to ensure system reliability and efficiency.**

Although limited in scope, our analysis shows the diversity and complexity of the impacts that a significant penetration of intermittent generation (mostly wind and solar, in practice) have on the technology mix and the operation of any considered power system. The possible future emergence of electricity storage options, as well as enhanced demand responsiveness, will also affect the need for flexible generation capacity, which is presently fueled by natural gas. The level and volatility of future energy prices will determine the volume and nature of investment in future generation under market conditions. Other regulatory frameworks should also be considered.

These complicated implications and trade-offs cannot be spelled out without the help of suitable computer models. The accuracy of the estimates of future fuel utilization and the adequate technology mix critically depends on the performance of these models. Unfortunately, the state-of-the-art computer models that simulate and optimize the capacity expansion and the operation of power systems and electricity markets — such as ReEDS or Memphis — are still in a development phase and fall short of the requirements to incorporate intermittent generation, storage, and demand response realistically, under a variety of energy policies and regulatory environments.

**RECOMMENDATION**

**A comprehensive appraisal of the economic, environmental, and reliability implications of different levels of significant penetration of renewable generation should be performed for power systems with different generation technology portfolios and under different energy policy scenarios.**

**The information obtained from this appraisal should inform a central piece in the design of energy policies that contemplate mandating large amounts of solar or wind generation.**

**Additional efforts should be made to expand or develop the sophisticated computation electric system models that are needed for this task.**

## NOTES

[1]Nameplate capacity is the nominal, maximum instantaneous output of a power plant.

[2]Absent other considerations, generation units are normally dispatched in economic merit order, i.e., those with lower variable operating costs first.

[3]Channele Wirmin, EIA, private communication.

[4]Steinhurst, W., *The Electric Industry at a Glance*, Nuclear Regulatory Research Institute, 2009.

[5]Electric Power Research Institute, *A Primer on Electric Power Flow for Economists and Utility Planners*, 1995; Pérez-Arriaga, I., Rudnick H., Rivier, M., Chapter One: *Electric Energy Systems, An Overview*.

[6]Hydroelectric generation, shown in Figure 4.2 as constant over demand periods, will in fact tend to be concentrated in particular seasons and peak periods of the day. The MARKAL model does not represent this detail, though its inclusion would have only a small effect on the figure as it aggregates all the national hydroelectric facilities.

[7]The same change in unit dispatch could be approached using various forms of direct regulation, options not studied here.

[8]The ReEDS model captures key characteristics of the electricity network's transmission constraints and reliability requirements by splitting the country into 134 geographic partitions. Each partition balances demand and supply of electricity by independently generating, importing, and exporting electricity. Collectively, subsets of these balancing areas constitute the independent system operators (ISOs) and regional transmission organizations (RTOs).

[9]As noted in the introduction of this section, the expected maximum capacity factor for an NGCC plant is 85%. The EIA projects that this could increase to 87% by 2016 (http://www.eia.doe.gov/oiaf/aeo/pdf/2016levelized_costs_aeo2010.pdf). The average fleet capacity factor of 87% from ReEDS for the 20% $CO_2$ reduction scenario approaches the upper generation threshold of the country's current NGCC fleet.

[10]Although the trend for NGCC displacement of coal generation remains the same for this updated scenario, these results are numerically different than the results presented in the interim report. The interim report showed opportunities for coal displacement in all time periods. The difference stems from assumptions about how much NGCC capacity exists in ERCOT. The NGCC capacity numbers used for this 2012 simulation are more conservative, and projected forward from 2006 EIA capacity and generation data (2006 is the start year for ReEDS).

[11]Presentation, "*Reducing Pollution from Power Plants,*" Gina McCarthy, Assistant Administrator, U.S. EPA Office of Air and Radiation, October 29, 2010.

[12]For a variety of reasons, deployment of required controls has been delayed, largely by court findings of legal flaws in various rulemakings. The New Transport Rule, which will replace CAIR in place today, is expected to be finalized in mid-2011 and will be implemented over time, with most coverage finalized by 2014. The Transport Rule will cover $SO_2$ and NOx. EPA released a proposed rule for mercury emissions from coal and oil-fired power plants in March, 2011 and plans to finalize the rule by the end of the year. A final rule on $CO_2$ for power plants is expected sometime in 2012.

[13]This break-even price assumes a NGCC variable O&M cost of $3.20/MWh, fuel price of $5.38/mmBtu, heat rate of 6.04 mmBtu/MWh, and $CO_2$ emissions of 0.053 tons/mmBtu. For coal, the calculation assumes a variable O&M cost of $4.30/MWh, fuel price of $2.09/mmBtu, heat rate of 10 mmBtu/MWh, and $CO_2$ emissions of 0.098 tons/mmBtu. The cost of NGCC and coal generation break-even when the sum of the variable O&M cost and price per ton $CO_2$ multiplied by the amount of $CO_2$ emitted are equal to each other, for the respective fuels. Start-up and shut-down costs, ramp rates, associated changes in emissions, and other costs that have not been fully modeled are not included in this calculation.

[14]MIT Energy Initiative's report on *Retrofitting of Coal-Fired Power Plants for $CO_2$ Emissions Reductions*, Cambridge, MA, 2009 (http://web.mit.edu/mitei/docs/reports/meeting-report.pdf).

[15]EIA AEO 2010.

[16] See Bentek study, How Less Became More: Wind, Power, and Unintended Consequences In the Colorado Energy Market, April 2010.

[17] See "Impact of intermittent renewable electricity generation on the technology mix and fuel consumption in the U.S. power system." Yuan Yao, Ignacio J. Pérez-Arriaga. CEEPR (Center for Energy and Environmental Policy Research), MIT, May 2011.

[18] The ReEDS simulations of this level of mitigation show a greater penetration of renewable generation than do the results of the EPPA model shown in Chapter 3, but the difference is not an important influence on the insights to be drawn from these calculations.

[19] Details of these cases are provided by Yao and Pérez-Arriaga, op cit.

# Chapter 5: Demand

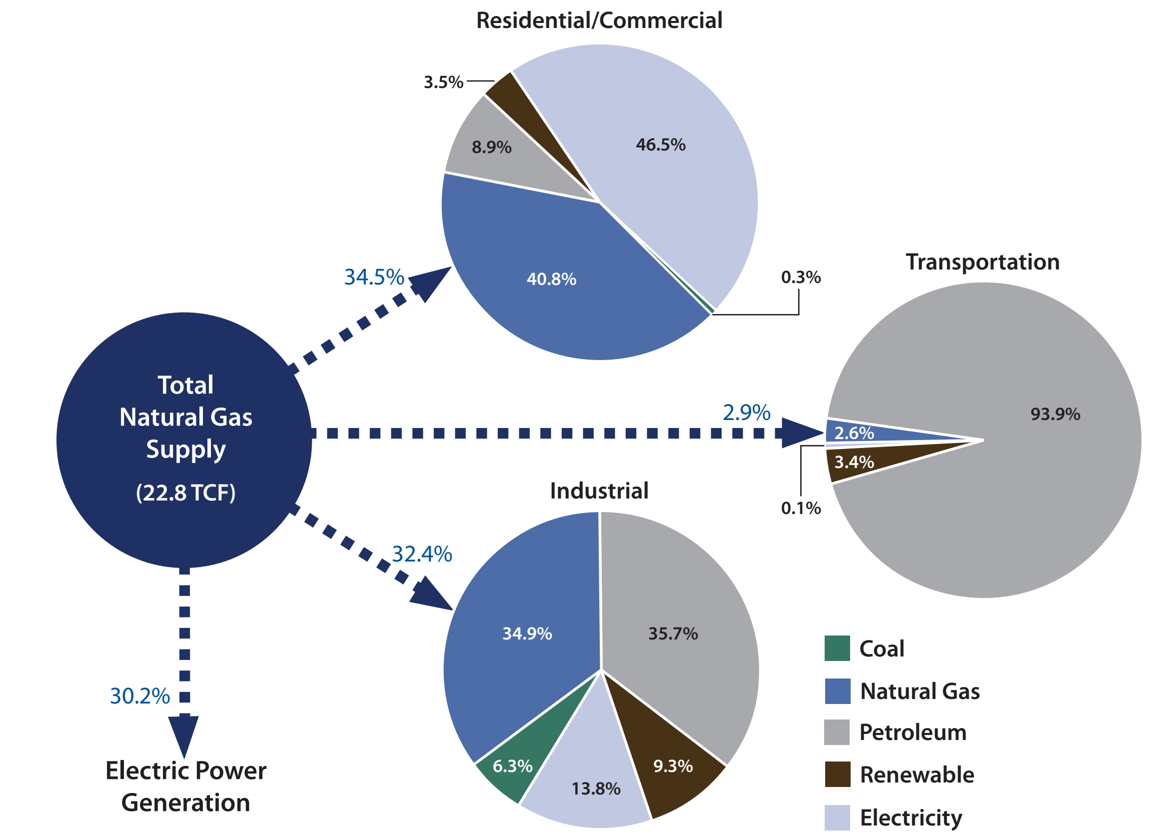
## INTRODUCTION

Natural gas is attractive for a variety of end-use applications because it is:

- clean burning;
- substantially less carbon intensive than coal and oil;
- efficient, with an average energy efficiency of 92% delivered to the burner tip;
- flexible, with use at small and large scales and responsive to demand changes; and
- versatile.

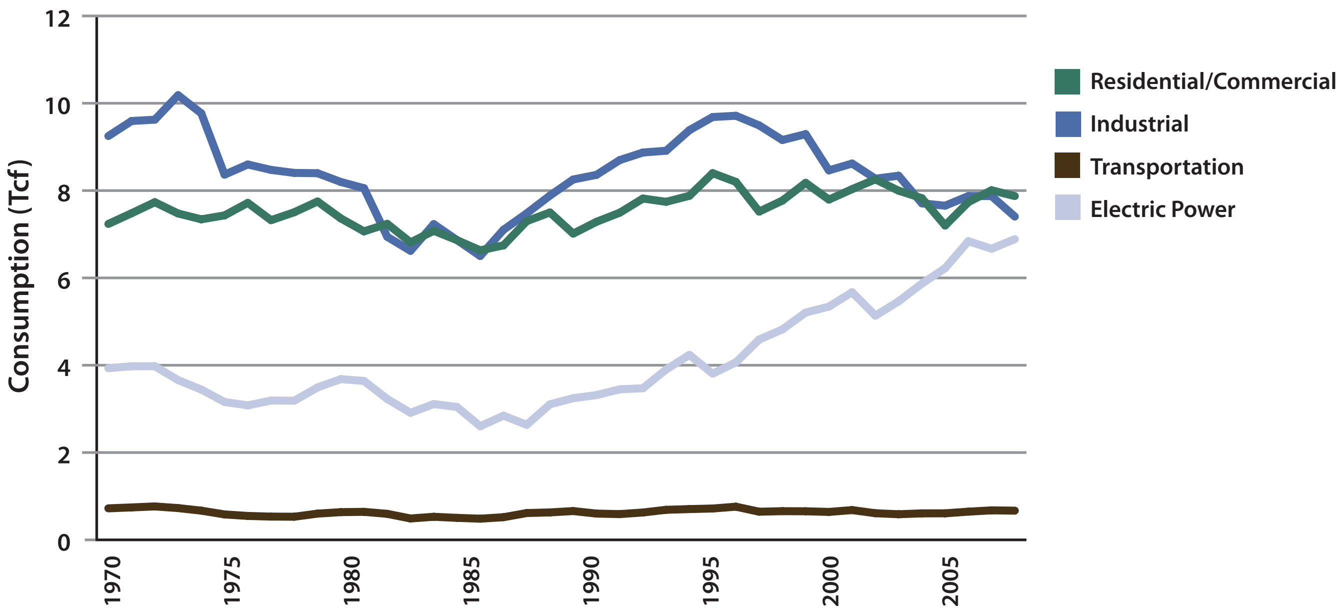
As shown in Figure 5.1, domestic natural gas supply is currently divided almost evenly among the Residential/Commercial, Industrial, and Electric Power Generation markets and has a substantial market share in each. This pattern has changed over time principally because of the substantial increase in natural gas use for electricity generation over the last 20 years, as seen in Figure 5.2, a trend that is likely to continue. On the other hand, natural gas plays a minimal role in the U.S. vehicular transportation sector, comprising only around 0.15% of the energy use. Natural gas use for transportation is mainly to power gas transport in pipelines.

**Figure 5.1 Natural Gas End-Use Markets (2009)**




Source: EIA

**Figure 5.2 Historical Trends in End-Use Consumption**




Source: EIA *Annual Energy Review 2009*

## CHAPTER OVERVIEW

We have analyzed a set of key issues in each of these sectors with a view toward possible significant increases or decreases in natural gas use, opportunities for emissions reductions and reduction of oil dependence in the transportation sector.

- In the industrial sector, over 60% of the total annual supply of 7.4 Trillion cubic feet (Tcf) of natural gas fires boilers and provides process heat, so we focus our analysis on efficiency in these uses and on the emissions reduction opportunities from coal displacement. Natural gas and Natural Gas Liquids (NGL) also play an important role as chemical feedstock, an issue of importance to domestic retention of manufacturing activity.

- In the Residential/Commercial sector, electricity and natural gas compete as the two major sources of energy supply. In the U.S., about 70% of electricity (an energy carrier) and 35% of gas (a thermal energy source) is used in buildings. Efficiency in delivering energy services to buildings and institutions will be an important differentiator, and our analysis focuses on two issues: end-to-end efficiency of electricity and gas, and the opportunities for natural gas combined-heat-and-power delivery systems.

- For the Transportation sector, our analysis focuses on the potential for natural gas to displace oil and reduce greenhouse gas (GHG) emissions both through direct use and indirectly through conversion to liquid fuels.

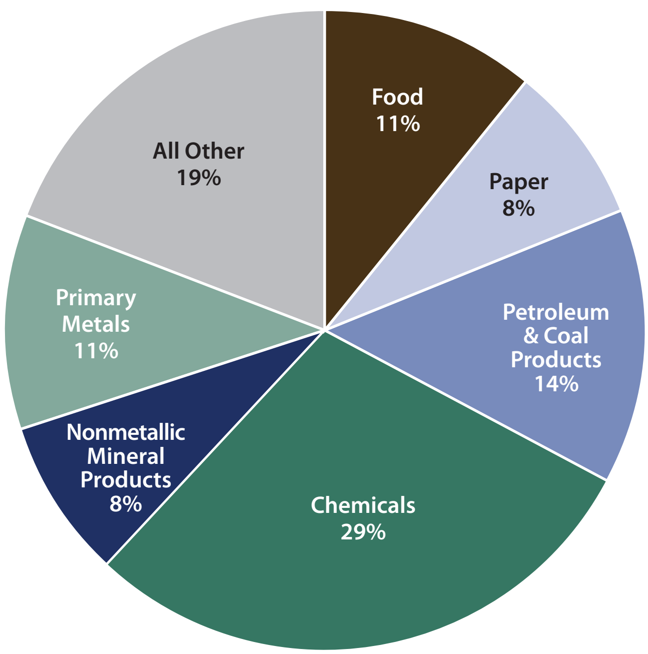
## NATURAL GAS IN THE INDUSTRIAL SECTOR

Industrial demand for natural gas was 7.4 Tcf in 2009, representing 32% of total U.S. natural gas use. Of this total, 1.3 Tcf was used in oil and gas field production and processing operations,[1] leaving a net total of 6.1 Tcf delivered to final customers for Industrial end-use applications. Natural gas accounts for 35% of total energy used in industry; petroleum products are the primary source of energy; and coal use is also significant.

Manufacturing comprises about 85% of total U.S. industrial natural gas use; the remaining 15% comprises non-manufacturing uses, such as mining. Six industries account for 81% of total manufacturing demand, as shown in Figure 5.3.[2]

In this section, we first present an overview of trends in natural gas use and efficiency in manufacturing and projections of future demand, discussing the interaction among changes in output, changes in fuel mix, and changes in end-use efficiency. We identify industrial boilers and process heating as the two principal uses of natural gas as a fuel, and discuss opportunities for changes in demand associated with improved efficiency as well as fuel switching. We also discuss potential for efficiency gains in process heating as well as research development and deployment (RD&D) opportunities.

**Figure 5.3 Natural Gas Use by U.S. Manufacturing Industry Sector**

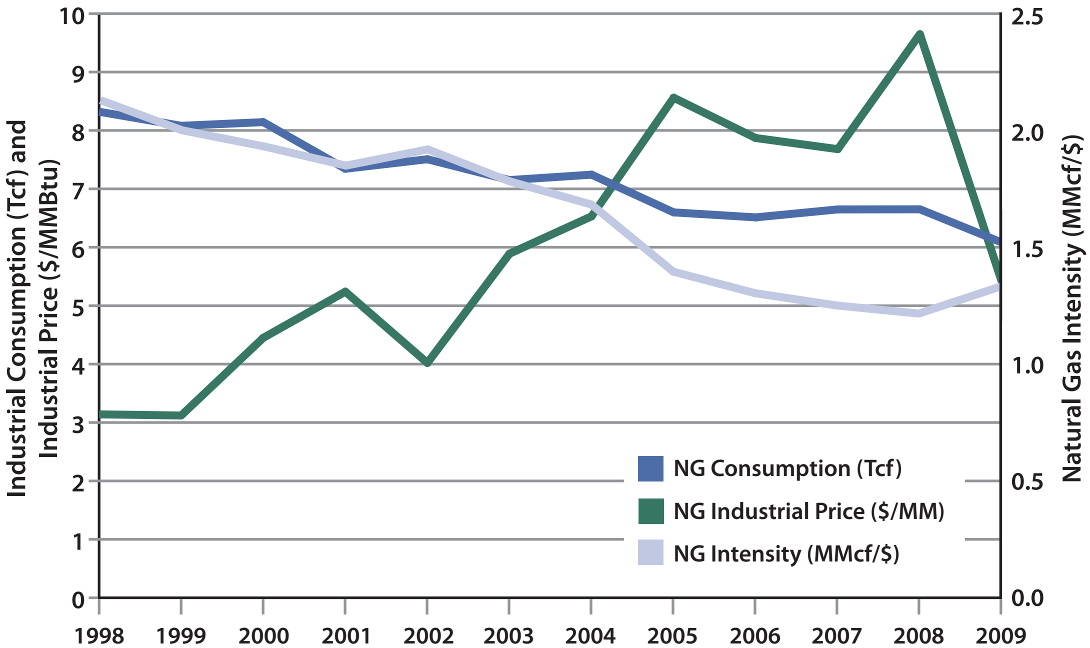



**"All Other" includes:**

- Beverage & Tobacco Products (0.7%)
- Textile Mills (1.1%)
- Textile Product Mills (0.8%)
- Apparel (0.1%)
- Leather & Allied Products (<0.1%)
- Wood Products (1.5%)
- Printing & Related Support (0.7%)
- Plastics & Rubber Products (2.2%)
- Fabricated Metal Products (4.1%)
- Machinery (1.4%)
- Computer & Electronic Products (0.8%)
- Electrical Equipment, Appliances, & Components (0.7%)
- Transportation Equipment (4.2%)
- Furniture & Related Products (0.3%)
- Miscellaneous (0.4%)

Source: EIA MECS

**Figure 5.4 Trends in U.S. Industrial Natural Gas Consumption and Intensity**




Source: EIA, BEA

## Natural Gas Consumption and Efficiency Trends

Since 1998, industrial natural gas use declined by 25%, or about 2.2 Tcf/year, the only end-use sector to do so.

Figure 5.4 shows that this decline has been steady, notwithstanding volatility in natural gas prices. The intensity of natural gas use (i.e., the quantity of natural gas used per dollar value of shipments) declined by more than total use, indicating that the reduction was due to a combination of increased efficiency of use and a shift to less energy-intensive activities. We estimate that natural gas consumption has declined at an average annual rate of 3%, while natural gas intensity has declined at an average annual rate of 5% over this period.

For energy-intensive industries, we estimate that the cost of natural gas as a percentage of value of shipments can range from 1% (for the food products industry) to as much as 50% in the case of nitrogen-based fertilizers. In other industry sectors that are less energy intensive, we estimate the cost of natural gas in the range of only 0.2% to 0.6% of the value of shipments. Notwithstanding the low ratios of natural gas costs to value of shipments in many manufacturing industries, volatility in the price of natural gas could have a significant impact on the competitive position of those industries that operate in global markets.

Several factors contribute to the price elasticity of gas in this sector. Higher natural gas prices, particularly in relation to prices abroad, can lead to reduced manufacturing output. Also, rising prices provide incentives for increased energy efficiency measures and fuel switching. Falling prices have an opposite effect on industry output and fuel switching.

Cost savings resulting from energy-efficiency gains are increasingly viewed as a business opportunity, since the savings flow directly to the bottom line. New energy-efficient capital investments can offer attractive returns on investment, competing with other corporate capital investment opportunities. A recent study conducted for the Pew Center on Global Climate Change documented the nexus between business profitability, improved energy efficiency and carbon dioxide ($CO_2$) emissions reductions. It showed that companies do best in reducing energy use when they set aggressive energy reduction targets, closely monitor progress, have active top management involvement, and take a comprehensive approach to analyzing energy-efficiency opportunities from manufacturing to marketing.[3]

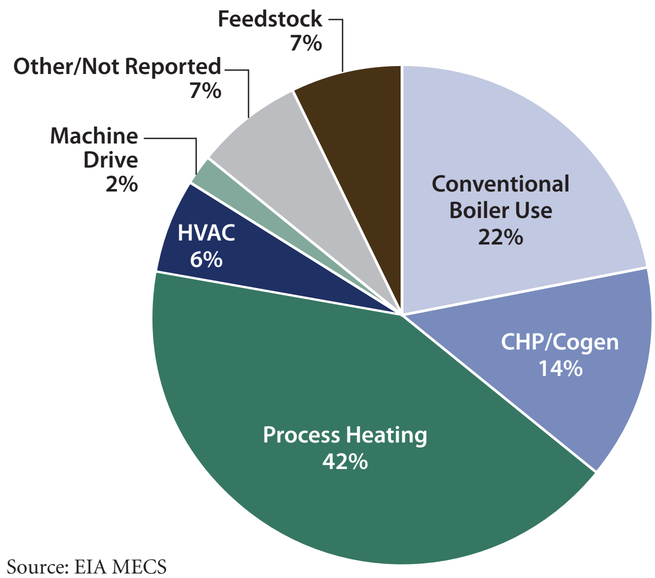
These general patterns are reflected in the U.S. Energy Information Administration (EIA) Annual Energy Outlook (AEO 2011). The AEO 2011 projects natural gas demand in the Industrial sector to rebound to pre-2000 levels, in excess of 8 Tcf/year, by 2015.[4] The net increase is attributed to continued recovery from the recession, increased combined heat and power (CHP), and demand response to lower natural gas prices, partly offset by continued gains in energy efficiency. The AEO 2011 projects the average annual growth in natural gas demand in industry at 0.9% through 2035, about half of the projected growth rate of 1.9% in the value of industry shipments, reflecting a continuing decline in natural gas intensity.[5]

The economic modeling analysis that underlies the results presented in Chapter 3 shows a similar pattern of Industrial gas demand over coming decades. Under the assumption of no additional policy on GHGs, U.S. Industrial gas demand grows over the period to 2035 and beyond. On the other hand, under the price-based policy explored in Chapter 3, which reduces national GHG emissions to 50% of 2005 levels by 2050, total industry gas demand declines over the next two decades as gas use shifts towards electric generation and away from other end uses. In the most energy-intensive U.S. manufacturing industries, gas use remains roughly constant at the 2005 level, substantially below the no-policy projection. However, because of modeled flexibility in this industry segment, the value of domestic output is only slightly below that in the no-policy case.[6]

### Principal Uses of Natural Gas as a Fuel and as a Chemical Feedstock

Natural gas is used in U.S. manufacturing both as a fuel and as a chemical feedstock. The two primary fuel uses are in boilers and process heating, and the two primary feedstock uses of natural gas are in ammonia ($NH_3$) manufacturing and hydrogen ($H_2$) production. Figure 5.5 shows that process heating accounts for 42% of manufacturing natural gas consumption, with boilers (conventional and combined heat and power) accounting for an additional 36%. These two applications total 4.5 Tcf/year, or over three-fourths of total natural gas used in manufacturing (and over 60% of total industrial use), and thus provide the focus for our analysis.

**Figure 5.5 U.S. Manufacturing Natural Gas Use by End-Use Application**




Source: EIA MECS

## Natural Gas Use in Industrial Boilers

Industrial boilers, both conventional and CHP, consumed 2.1 Tcf of natural gas in 2006, accounting for 36% of total natural gas in manufacturing.[7] We examine two potential drivers affecting demand for natural gas in boilers: modernization of the current natural gas boiler fleet with more efficient units, and replacement of coal boilers with new natural gas boilers. Our analysis is summarized in the discussion that follows; a more detailed discussion is provided in Appendix 5A.

Industrial boilers are used to provide steam and hot water in all manufacturing industries, with the four largest applications in chemicals (39%); food processing (17%); paper (13%); and petroleum and coal products (13%). There is strong competition among boiler fuels in the energy-intensive industries that employ larger boilers and have ready access to alternative fuel supplies. Natural gas is the predominant boiler fuel in other manufacturing industries, which typically employ smaller boilers and do not have the same opportunities for use of by-products and waste fuels.

Our analysis is based on a 100 Million British thermal units (MMBtu)/hour boiler[8], which is relatively large for natural gas boilers, but comparable to many coal boilers. As a sensitivity analysis, we also analyzed a smaller size boiler (50 MMBtu/hour.)

*Modernization of the Natural Gas Industrial Boiler Fleet*

Most existing natural gas boilers have been in service for decades and experience low turnover rates. On average, the existing fleet of pre-1985 boilers has an average energy efficiency in the range of 65% to 70%.[9] These boilers reject waste heat in the exhaust gases; this heat is comprised of the latent heat that can be recovered from condensing the water vapor into a liquid, as well as the sensible heat contained in the exhaust.

In 2004, the Department of Energy (DOE) set minimum energy-efficiency standards for new natural gas boilers in the range of 77% to 82%, depending upon boiler size and boiler technology.[10] New boilers meet this standard through the use of additional heat recovery systems (i.e., condensing technology) to capture the latent heat and a portion of the sensible heat in the exhaust gases. In addition, use of economizers allows for waste heat to be recovered by preheating the boiler feed water. These improvements can boost overall energy efficiency to the 80% to 85% level. Further technology advances entering the marketplace include multi-stage combustion systems — which also reduce NOx (a mixture of nitric oxide and nitrogen dioxide emissions) — and advanced condensers and air pre-heating systems. These "super"-efficient boilers can achieve efficiencies in the range of 94% to 95%.

We compared the net present value (NPV) of the pre-tax cost of replacing an existing 100 MMBtu/hour natural gas boiler with either a high-efficiency or super-high-efficiency unit. We estimate that replacement of current natural gas boilers with high-efficiency models would, at a 15% discount rate, yield a reduction of 8% in annualized costs on a pre-tax basis. Replacement with super-high-efficiency boilers would yield annualized savings of 20%. A sensitivity analysis on smaller size natural gas boilers (i.e., 50 MMBtu/hour) yields similar results.

The payback periods for these boiler replacements range from 1.8 to 3.6 years, based on 2010 actual industrial natural gas prices, and assuming no increase in natural gas prices over this period. Higher natural gas prices would improve the results; lower natural gas prices would reduce the projected annualized savings and extend the payback period.

The cost estimates are for equipment only; installation costs will reduce these returns somewhat. Also, in particular instances, the attractiveness of boiler modernization will depend on other factors such as: the remaining book value of existing boilers that a firm might write off; the availability of investment capital; the return on investment in boiler modernization relative to other opportunities; and the availability of tax incentives, such as accelerated depreciation or investment tax credits. Considering all these factors, however, it appears that replacement will be cost effective in many installations.

Two scenarios can provide an indication of the impact on natural gas consumption: (1) a replacement of 50% of current natural gas industrial boiler capacity with high-efficiency natural gas boilers would reduce demand for natural gas by 129 Billion cubic feet (Bcf) annually, while (2) a replacement of 50% of current natural gas boiler capacity with super-high-efficiency natural gas boilers would reduce demand by 263 Bcf annually. The reduction in $CO_2$ emissions ranges from about 4,500 to over 9,000 tons per year per boiler.

**FINDING**

**Replacement of existing industrial natural gas boilers with higher-efficiency models could cost-effectively reduce natural gas demand and reduce GHG emissions.**

**RECOMMENDATION**

**The DOE should review the current energy efficiency standards for commercial and industrial natural gas boilers and assess the feasibility of setting a more stringent standard.**

*Replacement of Existing Coal Industrial Boilers with Efficient Natural Gas Boilers*

A $CO_2$ emissions reduction requirement could lead to a significant level of replacement of existing coal boilers by natural gas. Absent a carbon constraint, a potential driver for fuel switching of coal boilers to natural gas is the establishment of National Emissions Standards for Hazardous Air Pollutants (NESHAPS) based on the application of maximum achievable control technology (MACT).

Our analysis is based on the February 23, 2011, Environmental Protection Agency (EPA) MACT emissions standards for mercury (Hg), metals, dioxin, acid gases, and other hazardous air pollutants emitted from industrial boilers and process heaters. On May 16, 2011, EPA administrator Jackson issued a stay of the new standards to allow for additional review and comment.

Natural gas boilers, because of the clean-burning nature of the fuel, are not subject to new emissions reduction requirements. On the other hand, three subcategories of coal boilers utilizing different technologies — stoker, fluidized bed, and pulverized coal combustion — are subject to new standards for the control of particulate matter, acid gases, toxic chemicals, and Hg. Achieving these emission standards will require the installation of wet scrubbers and fabric filters. Installation of activated carbon injection for control of Hg emissions also may be required in some instances.

The EPA economic analysis supporting the new MACT standards assumed that existing coal boilers would retrofit post-combustion controls. The EPA considered and rejected fuel switching as a control option, primarily because of assumed high natural gas prices ($9.58 per MMBtu for industrial delivery in 2008) and assumed 5% loss of efficiency from replacement of burners in existing boilers.

We performed an analysis, using current natural gas price assumptions, comparing four possible compliance options for coal boilers: (1) retrofit of post-combustion controls (using EPA cost assumptions); (2) retrofit of natural gas burners within the existing coal boiler (with EPA efficiency assumptions); (3) replacement of the existing coal-fired boiler with a high-efficiency natural gas boiler; and (4) replacement of the existing coal boiler with one of the new super-high-efficiency natural gas boiler technologies.

Our analysis indicates that replacement of coal boilers with efficient or super-efficient natural gas boilers is cost competitive with retrofitting post-combustion controls. The NPV cost, at a 15% discount rate, of high-efficiency natural gas boilers is slightly higher than the NPV cost of post-combustion controls, while the NPV of super-efficient boilers is slightly lower than the cost of retrofitting. The higher energy-efficiency performance levels of new natural gas boilers, at current gas prices, make boiler replacement an attractive option. Neither factor was considered in the EPA analysis.

The results of this analysis are sensitive to two assumptions: (1) the estimates of capital equipment cost for retrofitting post-combustion controls for coal and (2) the relative prices of coal and natural gas. Our analysis uses the EPA capital cost assumptions for installation of post-combustion controls (i.e., wet scrubbers and fabric filters at existing coal boilers). For coal boilers that may require additional controls to achieve MACT limits for Hg emissions, costs would increase substantially, making the options for replacement with natural gas boilers much more cost effective. The comparative results also are sensitive to the price differential between natural gas and coal. Based on actual average delivered prices in 2010, the price of natural gas was on average higher than coal by $2.31/MMBtu. A lower price differential (i.e., a smaller price spread between natural gas and coal) would make conversion to natural gas more attractive; a larger price differential would make continued use of coal more attractive.

The potential impact of replacing industrial coal boilers with new high-efficiency natural gas boilers is significant. The EIA Manufacturing Energy Consumption Survey (MECS) data show that industrial coal boilers and process heaters currently use 892 trillion Btu of coal each year. Conversion of this capacity to natural gas would increase demand for natural gas by 0.87 Tcf/year. The actual rate of market penetration would depend upon individual facility analyses.

Replacement of existing coal boilers with new efficient natural gas boilers in order to meet MACT requirements could reduce annual $CO_2$ emissions by 52,000 to 57,000 tons per year per boiler. We estimate that, even if the NPV cost of boiler replacement with natural gas is slightly more expensive than retrofitting post-combustion controls, assigning this incremental cost to the $CO_2$ reductions would yield an incremental cost for $CO_2$ reduction of about $5/ton.

**FINDING**

**Replacement of existing industrial coal boilers and process heaters with new, efficient natural gas boilers could be a cost-effective alternative for compliance with the EPA MACT Standards. Fuel switching has the potential to increase demand for natural gas while achieving substantial $CO_2$ emissions reductions at a modest incremental cost.**

### Natural Gas Use in Manufacturing Process Heating

The use of some form of process heating is ubiquitous across virtually all manufacturing sectors, accounting for 2.4 Tcf of natural gas consumption in 2006, or 42% of all manufacturing gas use (and nearly one-third of total industrial use). Three manufacturing industries — coal products (20%), primary metals (19%), and chemicals (16%) — comprise over half of process heating demand for natural gas.

Process heating involves the transfer of heat energy to materials in a manufacturing process through conduction, convection, or radiation, involving direct or indirect contact with steam or another hot fluid. Process heating is an integral step in the manufacturing of a variety of products including metals, rubber, plastic, concrete, glass, and ceramics. Process heating conditions can vary widely by temperature (e.g., several hundred to several thousand degrees Fahrenheit), by throughput rates (e.g., short or long contact periods), and by type of process (e.g., batch or continuous). Natural gas and electricity are the two primary sources of energy for process heat.

The DOE-sponsored collaborations involving National Laboratories and industry have identified four best management approaches to improving energy efficiency in process heating: (1) improve the efficiency of the combustion process; (2) reduce heat losses in the process of transporting and transferring process heat; (3) improve the overall rate of heat transfer from the process heat medium to the product; and (4) recover a portion of the residual waste heat.[11] The DOE reports that application of many of the identified best management practices can improve efficiency of process heating typically in a range of up to 10%, with some measures, such as preheating combustion air, increasing efficiency by 20% or more. These measures typically result in paybacks within a 24-month period.

Implementation of process heating efficiency improvements have to be carefully integrated with process operating parameters so as not to impair performance; for example, heat recovery and integration can make process control more difficult. Well-designed process heating improvements can actually enhance process performance and reduce environmental emissions. The Pew Center report[12] on industry case studies highlighted several such examples: (1) installation of oven draft controls at Frito-Lay tortilla chip operations not only saved natural gas, but also improved the quality of the chips; (2) waste heat recovery from the incineration of exhaust gases from painting operations at a Toyota manufacturing facility also enabled the plant to replace centralized steam generation with a distributed hot water supply system; and (3) replacement of existing ethylene furnaces at the Dow Chemical Freeport, TX, facility for compliance with NOx emissions requirements also improved process heating efficiency by 10%, and reduced $CO_2$ emissions by 105,000 tons/year.[13]

Significant reductions in demand for process heating may require changes in the underlying manufacturing processes themselves. These could include the substitution of membrane separation for temperature-based separations, more selective catalysts that reduce reaction temperatures, and greater process integration.[14] The steel industry achieved significant reductions in process heating requirements as a result of deployment of continuous casting machines and advances in near-net-shape casting that minimize the need for follow-up forming operations. In the chemicals industry, Dow and BASF deployed the world's first commercial-scale plant to convert hydrogen peroxide to propylene oxide, reducing energy use by 35% and wastewater production by 80%.[15] Research is underway to develop new catalysts that would achieve the oxidative coupling of methane to convert methane to ethylene, replacing the energy-intensive cracking process.[16] Other possible new approaches in the chemicals industry involve the utilization of biomass feedstock materials to replace conventional hydrocarbon feedstock, bio-processing technologies that may require less process heating, or both.

Finally, product substitution offers opportunities for reductions in demand for natural gas. Such examples include new cements, nanomaterials, and biomimetic materials that require less energy to produce than current materials.

**FINDING**

**The potential for significant reductions in the use of natural gas for process heating lies in a shift to new manufacturing process technologies that use less energy-intensive processes and materials.**

### RD&D Opportunities in Energy-Efficient Technologies

Additional opportunities for advances in industrial technologies lie in the nexus of energy efficiency, environmental quality, and economic competitiveness. Advances in energy-efficient process technologies are well incentivized by normal industry economics due to the potential to also improve profitability through either product improvements or cost reduction. Because these advances also provide important contributions to U.S. energy security and environmental policy goals, the DOE has historically played an important role. Under the former Industries of the Future Program, the DOE served as the convener of industry working groups that developed technology roadmaps. The DOE then funded selected RD&D projects consistent with the roadmaps. For example, the development of the "Super Boiler" described earlier in this chapter was the result of an Industrial Combustion Technology Roadmap prepared by a DOE-formed industry working group in 1999. The DOE subsequently cost shared an R&D effort with the Gas Technology Institute (GTI), a not-for-profit Research and Development (R&D) organization. The partnership was subsequently expanded to include other sponsoring and performing entities, including Cleaver-Brooks, Inc., which served as the commercialization partner.[17]

A 2001 evaluation of the DOE Office of Industrial Technologies (OIT) R&D program by the National Academy of Sciences concluded that "…the OIT industrial programs are cost effective and have produced significant energy, environmental, and productivity benefits for both the Industrial sector and the country."[18] The Academy report identified four lessons from the OIT experience: (1) the value of OIT as a catalyst for convening industry; (2) the advantages of early agreement on goals and metrics for success; (3) the importance of non-energy benefits to industry as a driver for the adoption of technology; and (4) the significance of demonstration as a means of promoting technology adoption. The $CO_2$ emission reduction benefits of DOE OIT supported technologies and activities undertaken since 1977 have been estimated at 187 million metric tons of carbon equivalent (MMTCe).[19]

Early in the last decade, termination of the Industries of the Future Program was proposed, on the assumption that market forces should drive the size and pace of future energy efficiency improvements in industry. The President's fiscal 2012 budget proposes to replace the Industries of the Future Program with a suite of new manufacturing R&D initiatives and a new critical materials innovation hub, focusing more on pre-competitive R&D targeted to transformational changes in manufacturing technologies.

**FINDING**

**Industrial energy efficiency RD&D programs supported by the DOE have historically led to significant improvements in energy-efficient technologies: technologies that also achieved significant reductions in $CO_2$ emissions while improving the economic competitiveness of manufacturing.**

**RECOMMENDATION**

**The DOE should continue to play a role in accelerating the development of new technologies that can improve energy efficiency. The DOE should again serve as a convener of industry technology working groups to develop roadmaps for future energy-efficiency technology improvements. Based on these roadmaps, the DOE should develop a federally funded RD&D portfolio consisting of applied pre-competitive R&D as well as transformational approaches. The DOE RD&D portfolio should encompass both industry-specific technologies in energy-intensive industries and crosscutting technologies applicable across a broad spectrum of manufacturing industries.**

### CHP Systems for Industrial Applications

In most cases, industrial boiler and process heating installations typically support a single application. The modification of current process heating and industrial boilers to enable CHP applications could have a significant impact on natural gas demand.

Installation of CHP systems does not necessarily increase the efficiency of the process heat or steam system, nor does it generate electricity more efficiently than a large-scale central station power plant. The attractiveness of CHP stems from the increase in overall system efficiency that can be achieved by obtaining both electric power generation and steam generation from a single on-site system. CHP results in increased demand for natural gas at the industrial point of use site, with some offsetting reduction in demand for fuels at central station power generation facilities. From an energy systems standpoint, the improvement in overall energy efficiency has to take into account the reduction in purchased electricity, which reduces demand for electricity from the grid.

The feasibility of CHP applications in manufacturing depends upon the ability to match the quantity and quality of the steam or hot water produced from the CHP system with the industrial end-use requirements for heat and power. For industrial applications, CHP systems are designed to meet heat loads, because it is easier to balance electricity generation and load with the electrical grid. If the level of electricity generation is less than the manufacturing load, the facility purchases the remainder from the grid; if CHP electricity generation exceeds electrical load, the excess is sold back into the grid. Matching CHP systems to heat and power loads at smaller scale, such as institutional, commercial and residential applications, is more challenging, as discussed later in this chapter.

The EIA reported[1] that 964 Bcf of natural gas was used for industrial CHP in 2009, representing 13% of total industrial natural gas use. The EIA AEO 2011 projects an increase of 181% in electricity generated from end-user CHP systems by 2035.[20] While this would imply an increase in natural gas use of about 1.7 Tcf per year by 2035, this increase is essentially offset by other energy-efficiency gains in the Industrial sector, so that the EIA projection shows relatively flat demand for natural gas in the industry sector from the period 2015 to 2035. In addition, increased demand in the Industrial sector for CHP also would mitigate increases in demand for grid-supplied electricity.

### Natural Gas Use as a Chemical Feedstock

About 7%, or 0.36 Tcf, of natural gas demand in manufacturing is for use as a feedstock for the production of hydrogen and ammonia. Hydrogen is used extensively in the petroleum-refining industry to upgrade petroleum products, and ammonia is primarily used in the manufacture of fertilizer products. In addition, NGLs, which consist primarily of ethane and propane, are key feedstock materials for manufacturing of a variety of chemical products.

Our detailed analysis of chemical feedstock issues is presented in Appendix 5B. The analysis indicates that lower natural gas prices make the operation of current domestic ammonia manufacturing capacity more competitive in the global market. Ammonia is the key intermediate step in the manufacturing of a variety of nitrogenous fertilizer products. We also estimate that, due to current petroleum/natural gas price spreads, NGLs will have significant cost advantage relative to naphtha in the domestic manufacturing of ethylene. Ethylene is an intermediate product in the manufacturing of polyethylene, polyvinyl chloride, and other plastics. We have not estimated changes in U.S. natural gas demand associated with potential changes in global market competitiveness of these commodities; this is dependent upon other factors, such as global demand projections and capital investment plans, which are outside the scope of our analysis.

The demand for NGLs for domestic ethylene production will incentivize increased production of NGLs from domestic natural gas resources that are relatively "wet" (i.e., higher NGL content). The implications for NGL processing and infrastructure are discussed further in Chapter 6 on Infrastructure and in Appendix 5B.

## COMMERCIAL AND RESIDENTIAL APPLICATIONS OF CHP SYSTEMS

Smaller-scale CHP systems are available for applications in Residential and Commercial settings. There is a wide variety of technology options for smaller-scale CHP systems, including fuel cells, gas turbines, micro-turbines, and reciprocating engines (such as the Stirling engine). Except for fuel cells, these technologies rely on the combustion of fossil fuel to produce heat, later converted into mechanical energy to drive the generator that produces electricity. Fuel cells are based on electrochemical conversion of the chemical energy stored in hydrocarbon fuels into water and electric energy.

The choice of CHP technology for a particular application will depend on the different characteristics of the technology and how they match end-use requirements: [21]

- Natural gas micro-turbines have relatively high capital costs, but have lower maintenance costs than other technologies. Micro-turbines have a high-quality exhaust that can be used to increase the production of high-pressure steam for other high-temperature applications. However, turbines are sensitive to changes in ambient air conditions, and have a poor efficiency at part-load conditions;

- Reciprocating engines have low investment costs, good part-load performance, and quick start-ups. Their principal disadvantages include high maintenance costs, high noise levels, and high air emissions; and

- Fuel cells have high initial capital costs, but are virtually emissions free at the point of end use, and are quiet and efficient over a range of loads.

Additional details on performance characteristics and cost data of CHP technologies are provided in Appendix 5C.

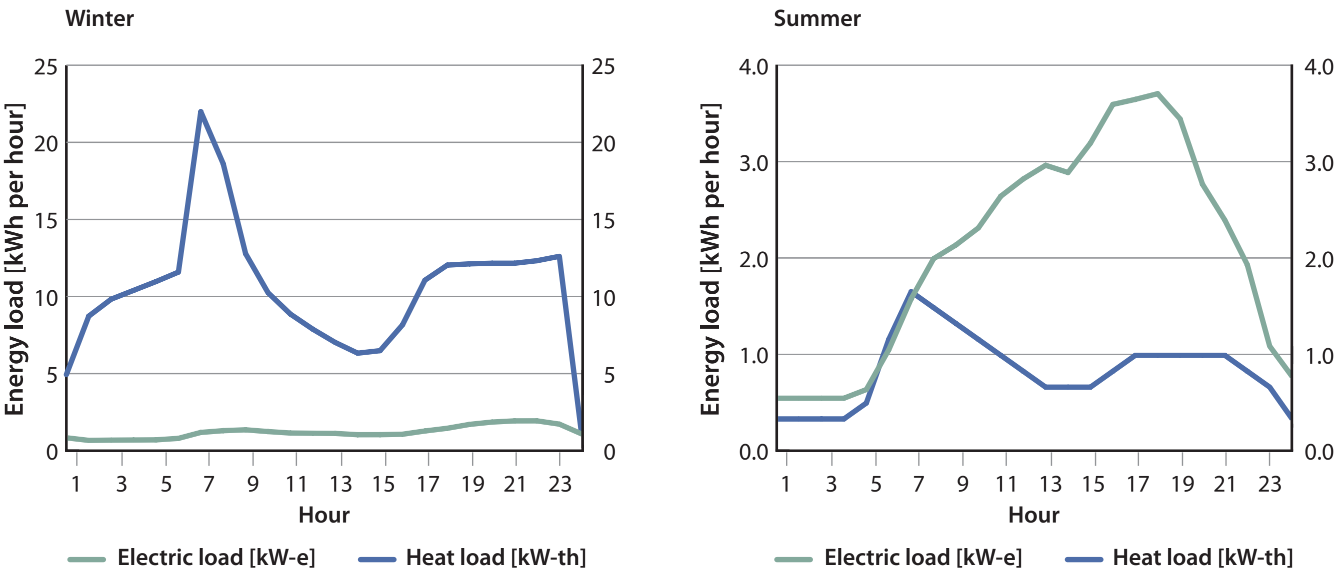
A critical parameter in assessing the feasibility of a CHP system is the ability to match the heat-to-power ratio (HPR) of the CHP system with the power and heating loads. As the size of the application becomes smaller, matching the HPR characteristics of the CHP system to load becomes a greater challenge, since it will depend on the CHP system's technical characteristics and its suitability to meet the variation in the customer's heat and power-load requirements. In Residential applications, micro-CHPs have very small electrical capacities (less than 5-kilowatt electric (kW-e)), with different efficiency and HPR values depending on the conversion technology. Fuel cells offer the highest electrical efficiency, followed by reciprocating engines and Stirling engines. By comparison, Stirling engines have a relatively high heat output per unit of electrical generation (i.e., high HPR), followed by reciprocating engines, and with a relatively low HPR for fuel cell technologies.[22]

To gain further insight on these trade-offs, we performed an analysis of several scenarios for application of CHP systems in smaller-scale Institutional and Residential applications. We chose the MIT campus as a case study for CHP application in an Institutional market. The MIT CHP system consists of a 21 megawatt electric (MWe) gas turbine combined with a Heat Recovery Steam Generator (HRSG) to generate steam from the turbine exhaust gas. The MIT CHP system provides about 75% to 80% of the campus electrical load and the majority of the campus steam requirements. The gas turbine has been used mostly as baseload power, with the remainder of electricity purchased from the grid. The remaining steam load not served by the CHP system is met with conventional boilers. We analyzed the costs of the MIT CHP system relative to a no-CHP option, i.e., purchasing all electricity from the grid and generating all campus steam requirements from boilers. Our analysis showed that installation of a CHP system provided a present value cost savings of about 20%, at a discount rate of 7.1%, with a corresponding reduction of about 17% in $CO_2$ emissions.[23] Our findings are described in more detail in Appendix 5C.

Another potential application for CHP is in district heating/cooling systems. District heating/cooling is a system for distributing heat (in the form of steam or hot water) or chilled water generated in a centralized location for residential or commercial space heating/cooling and hot water applications. District heating is used extensively in a number of European countries for industrial, commercial, and residential applications. For example, over six in ten homes in Denmark are served by district heating; market penetration is 50% or more in Poland, Sweden, and Estonia; and geothermal-based district heating serves 95% of Iceland's residences. U.S. experience is much more limited and focused on institutional users. While the U.S. currently has over 500 district heating/cooling systems,[24] about 85% serve hospitals and university campuses (such as the MIT campus used as a case study in our analysis). The U.S. also employs 85 urban utility district heating systems, serving about 1.9 billion square feet of commercial space.[25] Most U.S. district heating systems are single-purpose systems, but there is growing interest in CHP systems for this purpose. To stimulate this market, the DOE cost-shared several new CHP district heating projects using funds from the American Recovery and Reinvestment Act (ARRA). As the MIT case study illustrates, the market opportunities for expanded CHP district heating systems are promising.

We also examined the feasibility of CHP systems for residential applications in New England. As illustrated in Figure 5.6, there is a considerable mismatch between electricity and heating requirements. During winter, the heat load is significantly higher than the power load, while during summer, the power load is significantly higher due to demand for air-conditioning.

**Figure 5.6 Hourly Energy Load Profile for One Type of Residential Customer in New England – Sample for One Day during Winter and Summer**




Source: MITEI

Our analysis shows that the energy, environmental, and economic benefits of a CHP Residential application varied greatly depending upon the customer energy management strategy. Designing and operating a Residential CHP system to follow heat loads was economically competitive, with the greatest benefit during the winter season. Operating the CHP system to follow electricity requirements was not economically attractive, because the CHP system would produce large quantities of excess heat during summer months, significantly reducing overall performance of the system.

Finally, for the residential applications, a technology such as fuel cells, with a relatively low HPR, was more attractive than an alternative engine-based technology with higher HPR. The relative high electric efficiency of fuel cells makes this technology competitive for meeting electrical loads.[26] The detailed results of the MIT and New England Residential case studies are described in greater detail in Appendix 5C.

**FINDING**

**Matching heat and power loads for residential and other small-scale applications poses a significant challenge to the feasibility of small-scale CHP systems based on current technologies.**

## NATURAL GAS DEMAND IN BUILDINGS

The residential/commercial sectors account for over 40% of total energy consumption in the U.S., almost exclusively in buildings. While these two sectors represent over two-fifths of overall energy demand, they account for more than 55% of the nation's natural gas demand when the natural gas used to generate electricity for buildings is added to the direct use of natural gas in homes and businesses.[27]

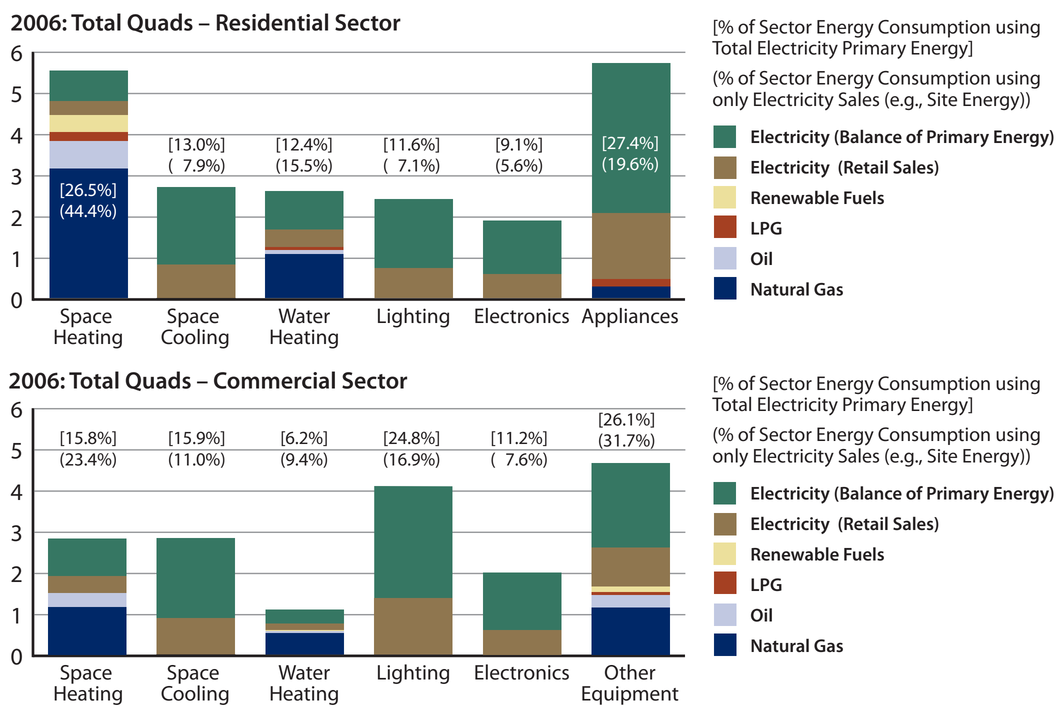
Within the residential/commercial sectors, the direct use of fuels such as natural gas, fuel oil, and liquid petroleum gas (LPG) are concentrated in thermal end uses, especially space heating and hot water. Figure 5.7 shows the breakdown of energy consumption for major end uses in the residential/commercial sectors. Of particular note are the differences between electricity and direct fuel consumption across different end uses, and how this influences not only the sales of electricity, natural gas, and other fuels, but overall energy consumption once electricity conversion losses are included. As can be seen, electricity and fuel sales — often called "site energy" — mask overall energy consumption since only about a third of energy consumed in power generation becomes electricity sold to the consumer.

## Comparing the Efficiency of Space Conditioning and Hot Water Technologies

When considering policies to cost-effectively reduce energy consumption and $CO_2$ emissions in buildings, it is important to consider both the end use and the energy carrier. This is especially true when looking at appliances and building energy systems than can be run on either electricity or fuels such as natural gas. Until recently, buildings commonly had separate systems for heating and cooling. Boilers or furnaces for heating can run on natural gas, oil, and LPG. As shown in Figure 5.7, space cooling which usually includes humidity control (e.g., air-conditioning (AC)) is almost exclusively electricity based, although large Commercial AC systems are available that run on natural gas, and in the past, gas-fired AC systems for the residential sector have been commercially available.

In the last several decades, heat pump systems have become much more common. A heat pump is essentially an air conditioner that can run backwards, delivering either hot or cold air to a building's interior. Most heat pump systems are air-source heat pumps, using external air as the temperature reservoir from which to provide heating or cooling. This is sufficient for regions that experience mild winters, but not where temperatures get very low for very long.[28]

**Figure 5.7 2006 Breakdown of Building Energy Consumption in the Residential and Commercial Sectors**




Source: DOE *Buildings Energy Data Book* (Oct. 2009)

Ground source (or geothermal) heat pumps, which use the temperature of the earth instead of the air to provide heating and cooling, overcome this cold winter problem. However, this comes at a significant increase in installed costs since an external heat exchange loop needs to be installed in the ground outside the building. The cost of this heat exchanger can vary significantly depending on the type of ground source heat pump, soil type, and temperature.

Hot water systems are more straightforward since the seasonality of use is less of a factor. Common systems use the heat from fuel combustion or electric resistance heating to keep a tank of water at the desired temperature. Recently, heat pump hot water systems have entered the market, as have instantaneous (or tankless) water heaters.

For all of these systems, whether furnaces, central AC, heat pumps, or hot water heaters, the differential equipment and life-cycle costs of systems are important factors to builders, homeowners, and policy makers, as builders seek to minimize installed costs, consumers seek to minimize operating costs, and policy makers seek to minimize social costs including effects on the environment. Balancing all these factors is challenging especially when comparing systems that use different energy carriers, in particular electricity versus natural gas and other "direct" use fuels.

As described in more detail in Appendix 5D, there is a broad range of efficiency metrics for furnaces, air conditioners, heat pumps, and hot water heaters that offer little guidance to consumers when trying to compare technologies across fuel types. Even heat pumps, which provide both space heating and AC, have different efficiency metrics depending on whether they are in heating or cooling mode, or use outside air versus the temperature of the earth as a heat source/sink. For furnaces, air conditioners, and air source heat pumps, these efficiency metrics are also "averaged" across reference heating or cooling seasons, and so do not inform individual consumers about how they might perform locally. Even this rough seasonal adjustment is not possible for ground-source heat pumps, since baseline ground temperature information is not available. And so, ground source heat pump manufacturers report an optimal, and substantially higher, coefficient of performance than reported for air-source heat pumps.

To allow comparison, we normalize these diverse efficiency metrics for select Residential appliances and space conditioning systems in Table 5.1.[29] This table focuses on the Residential sector, since it is larger in both overall size and the number of systems in the field, and also because it is an area where policies including appliance efficiency and building standards may overcome market inertia, especially as it pertains to equipment versus life-cycle cost calculations for smaller, less experienced consumers.

Table 5.1 shows the "Seasonal Co-efficient of Performance" (SCOP) for a range of Residential heating, cooling, and hot water systems, across a range of commercially available systems, including "low" energy efficiency systems, higher efficiency "Energy Star" systems (minimum efficiency to qualify as an Energy Star system), and a best-available energy efficiency system. The SCOP is simply the ratio of the amount of useful energy provided divided by the amount of retail energy (fuel or electricity) consumed. For direct thermal systems, such as furnaces, the efficiency or SCOP will be less than one. However, for AC and heat pump systems, where the electricity moves heat between the inside and outside, instead of consuming the electricity as heat, the amount of useful energy can be substantially greater than the "thermal value" of electricity, resulting in SCOPs in the range of two and a half to seven.

**Table 5.1 Site vs. Source Energy Efficiency of Residential Heating, Cooling and Hot Water Systems**

| | Site Energy Efficiency (SCOP*) | | | Source-to-Site Efficiency | Full-Fuel-Cycle Efficiency (FFC) | | |
|---|---|---|---|---|---|---|---|
| | Low | Energy Star | Best | | Low | Energy Star | Best |
| **Heating System Type** | | | | | | | |
| Electric Furnaces | 0.95 | — | 0.99 | 0.32 | 0.31 | — | 0.32 |
| Oil-Fired Furnaces | 0.78 | 0.83 | 0.95 | 0.88 | 0.69 | 0.73 | 0.84 |
| Gas-Fired Furnaces | 0.78 | 0.90 | 0.98 | 0.92 | 0.72 | 0.83 | 0.90 |
| Air Source Heat Pumps† | 2.30 | 2.40 | 5.20 | 0.32 | 0.74 | 0.77 | 1.67 |
| Ground Source Heat Pumps‡ | 2.50 | 3.30 | 4.80 | 0.32 | 0.80 | 1.06 | 1.54 |
| **Cooling System Type** | | | | | | | |
| Central AC† | 3.81 | 4.25 | 6.74 | 0.32 | 1.22 | 1.37 | 2.17 |
| Air Source Heat Pumps† | 3.81 | 4.25 | 4.98 | 0.32 | 1.22 | 1.37 | 1.60 |
| Ground Source Heat Pumps‡ | 2.55 | 4.13 | 6.57 | 0.32 | 0.82 | 1.33 | 2.11 |
| **Hot Water System Type** | | | | | | | |
| Electric Storage Tank | 0.92 | — | 0.95 | 0.32 | 0.30 | — | 0.31 |
| Oil-Fired Storage Tank | 0.51 | — | 0.68 | 0.88 | 0.45 | — | 0.60 |
| Gas-Fired Storage Tank | 0.59 | 0.62 | 0.70 | 0.92 | 0.54 | 0.57 | 0.64 |
| Electric Heat Pump Tank | 0.92 | 2.00 | 2.35 | 0.32 | 0.30 | 0.64 | 0.76 |
| Electric Instantaneous | 0.93 | — | 0.99 | 0.32 | 0.30 | — | 0.32 |
| Gas-Fired Instantaneous | 0.54 | 0.82 | 0.94 | 0.92 | 0.50 | 0.75 | 0.87 |

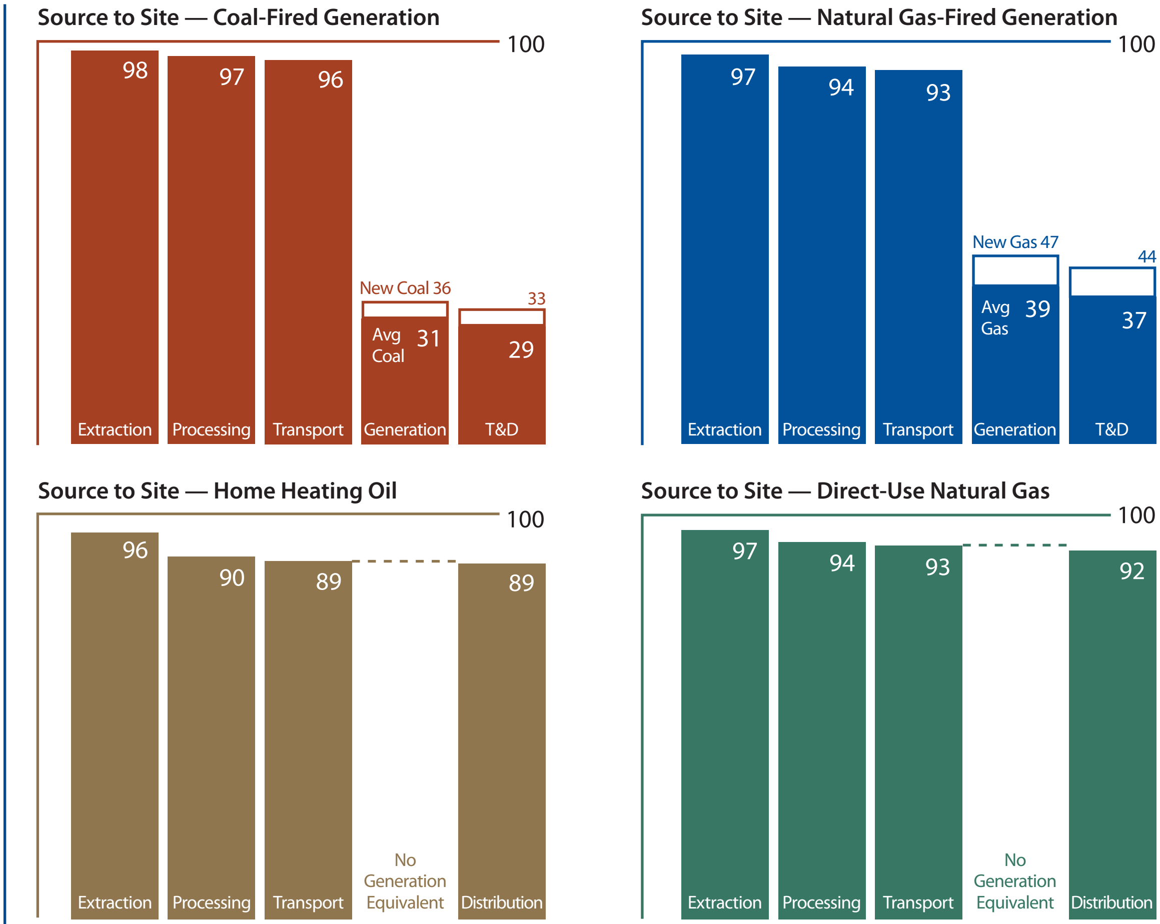
Source: MITEI

*COP for Ground Source Heat Pump Systems, †Split Systems, ‡Closed Loop Systems

More importantly, Table 5.1 shows the difference between "site" (SCOP) and "source" (Full-Fuel-Cycle (FFC)) energy efficiencies. FFC efficiencies account for all the energy used to extract, refine, convert, and transport the fuel to the end user, as well as the efficiency of the end-use equipment. Almost all building energy equipment is sold on the basis of end-use or "site" energy efficiency. However, looking at site or end-use efficiency alone masks large energy conversion losses, particularly those from generating electricity. FFC efficiency combines these source-to-site losses with end-use energy consumption.

Figure 5.8 shows the source-to-site energy losses of bringing energy to the consumer. All fuels, whether coal or natural gas for power generation, or oil and natural gas for household use, consume some energy in the extraction, processing, and bulk transportation of fuel. There is also additional energy use or losses in the delivery of electricity and fuels to the retail customer, such as the transmission and distribution (T&D) of electricity, distribution systems for natural gas, or truck delivery of home heating oil. The biggest difference comes in the conversion losses associated with electricity production. When these are all added together, source-to-site losses for electricity are 68%, compared to 8% for natural gas and 12% for home heating oil.[30] These source-to-site losses are then combined with end-use energy efficiencies to calculate the FFC efficiencies as shown in Table 5.1.

**Figure 5.8 Combined Source-to-Site Energy Efficiencies for Delivering Coal and Natural Gas-Fired Generation Versus Oil and Natural Gas to End-Use Customers**




Source: GTI and EIA[30]

**FINDING**

**Source-to-site energy losses should be considered when choosing among energy options, especially ones that use different energy carriers.**

In 2009, a National Research Council report recommended that the DOE move to the FFC approach in setting energy efficiency and appliance standards, especially when there are multiple fuel choices. In 2010, the DOE initiated a rulemaking process to move toward the FFC approach in the design of efficiency standards for appliances and space conditioning and hot water systems.[31]

The main comparison to draw from Table 5.1 is that although heat pump systems, as well as central air conditioners, have significantly higher site energy efficiencies, when roughly two-thirds losses in electricity generation and transmission are included, these gains effectively disappear except for the most efficient systems. Thus, improved efficiency information is needed to allow consumers to accurately compare the overall energy efficiency and cost effectiveness of direct fuel and electricity end uses. This is especially true for space conditioning and hot water systems.

**RECOMMENDATION**

**Improved energy-efficiency metrics that provide an FFC comparison of energy efficiency should be incorporated into national standard setting activities. The improved metrics should include both FFC efficiency and cost-to-consumer factors.**

### Looking Beyond Equipment Efficiency Standards

FFC and end-use efficiencies alone are not enough to determine which building energy systems will have the lowest cost to the consumer. The cost effectiveness of space conditioning and other technologies is a mix of equipment efficiency and fuel costs, equipment costs (including operation and maintenance costs), as well as the duty-cycle of the system. For example, a less efficient electric furnace may be more cost effective, on a total cost-to-consumer basis, in regions where it gets cold only occasionally, electricity prices are low, or the housing unit is not occupied year round.

The depth and duration of a region's heating and cooling seasons have a dramatic impact on the applicability and overall cost effectiveness of different energy technologies. Heating and cooling degree days are a rough estimate of a region's annual heating and cooling needs, and compare the daily average temperature to a reference temperature (usually 65°F in the U.S.). For example, New York City and St. Louis have 40% fewer heating degree days than Minneapolis-St. Paul. However, St. Louis is considerably warmer than New York City, with almost half again as many cooling degree days.

Different regions of the U.S., and even different locations within states, have very different heating and cooling requirements, and so generic appliance efficiency standards may not provide enough information to make the best choice. As such, no city is "typical," and, therefore, tailored information is needed in order for consumers, architects, builders, and others to make better choices. Add to this information about regional building stock age and efficiency, and demographic factors, and the need for a more nuanced approach to designing cost-effective, low-carbon building energy policies becomes more pronounced.

**FINDING**

**Energy-efficiency metrics alone are not sufficient to inform consumers about the most energy-efficient and cost-effective options for meeting household energy needs in different regions.**

Although "Energy Guide" labels for appliances such as hot water heaters, air conditioners, and heat pumps are commonplace in retail establishments, comparative energy and life-cycle cost information is far from prominent in stores and on major retailers' websites, even when performing head-to-head comparisons of similar products.

**RECOMMENDATION**

**In addition to improved efficiency metrics for comparing appliances and building energy technologies, there is a need to inform consumers and developers as well as state and local regulators about the cost-effectiveness and suitability of various technologies, relative to local conditions.**

## FFC Efficiency and $CO_2$ Emissions

When considering climate policy, the situation becomes even more complex. While the carbon content of retail fuels is reasonably consistent across the U.S., this is not so for electricity, where regional differences in the mix of generation can substantially impact the $CO_2$ emissions associated with electricity use. Table 5.2 shows how source-to-site efficiency factors and $CO_2$ emissions rates change across the continental U.S. Efficiency and emissions factors are also shown by North American Electric Reliability Corporation (NERC) region.

In all cases, source-to-site $CO_2$ emissions from direct combustion of fuels are substantially lower than from the use of electricity. Regions with greater concentrations of coal-fired generation commonly have *both* higher source-to-site losses, as well as higher carbon content fuels. Also included in Table 5.2 are the pre-combustion $CO_2$ emissions from the extraction, processing, and transportation of bulk fuels. The source-to-site efficiency factors for electricity in Table 5.2 vary by -11% to +18% around the national average of 32%. Most of this is due to the fuel mix, especially the mix of coal versus natural gas, nuclear, and hydropower in each NERC region. These differences become magnified in a measure of $CO_2$ emissions per unit of generation, where (in 2005) the $CO_2$ content of electricity varied by +36% to -30% around the national average of 1,470 lb. $CO_2$ per Megawatt hour (MWh).

**Table 5.2 Retail Electricity and Fuel – Source-to-Site Efficiencies and $CO_2$ Emissions**

| Regional Site-to-Source and $CO_2$ Emissions Factors by NERC Region (2005) | | Source-to-Site Efficiency | $CO_2$ Emissions (lb $CO_2$/MWh) Precomb. | Generation | T&D | Combined | Δ% from US Avg. |
|---|---|---|---|---|---|---|---|
| **United States Average** | **US** | **0.32** | **54** | **1,329** | **86** | **1,469** | **–** |
| Midwest Reliability Organization | MRO | 0.28 | 55 | 1,824 | 120 | 1,999 | 36.1 |
| Southwest Power Pool | SPP | 0.30 | 63 | 1,751 | 114 | 1929 | 31.3 |
| Reliability First Corporation | RFC | 0.31 | 38 | 1,427 | 94 | 1,559 | 6.1 |
| Florida Reliability Coordinating Council | FRCC | 0.33 | 99 | 1,319 | 91 | 1,508 | 2.6 |
| SERC Reliability Corporation | SERC | 0.31 | 45 | 1,369 | 90 | 1,504 | 2.4 |
| Texas Regional Entity | TRE | 0.32 | 74 | 1,324 | 87 | 1,485 | 1.1 |
| Western Electricity Coordinating Council | WECC | 0.38 | 51 | 1,033 | 57 | 1,142 | -22.3 |
| Northeast Power Coordinating Council | NPCC | 0.33 | 85 | 876 | 61 | 1,022 | -30.4 |
| **Primary Residential Fuels** | | | Precomb. | Distribution | Combustion | Combined | |
| Distillate Oil | US | 0.89 | 107 | 4 | 550 | 661 | -55.0 |
| Liquid Petroleum Gas | US | 0.89 | 74 | 4 | 476 | 553 | -62.3 |
| Natural Gas | US | 0.92 | 36 | 5 | 404 | 444 | -69.8 |

Source: Energy and Emissions Factors for Building Energy Consumption, Gas Technology Institute, 2009.

**Table 5.3 Combined Energy and Emissions Impacts of Using FFC Efficiency for Select NERC Regions for Energy Star Appliances**

| | Energy Consumption (MWh) | | | Full Fuel Cycle $CO_2$ Emissions (Ton $CO_2$) | | | | |
|---|---|---|---|---|---|---|---|---|
| | Useful | Site | FFC | National | MRO | NPCC | SPP | TRE |
| **Heating System Type** | | | | | | | | |
| Electric Furnaces | 100 | 101.0 | 314.2 | 74 | 114 | 49 | 104 | 75 |
| Oil-Fired Furnaces | 100 | 120.5 | 136.7 | 45 | | | | |
| Gas-Fired Furnaces | 100 | 111.1 | 120.7 | 27 | | | | |
| Air Source Heat Pumps | 100 | 41.7 | 129.6 | 31 | 47 | 20 | 43 | 31 |
| Ground Source Heat Pumps | 100 | 30.3 | 94.3 | 22 | 34 | 15 | 31 | 23 |
| **Cooling System Type** | | | | | | | | |
| Central AC | 100 | 23.5 | 73.2 | 17 | 27 | 11 | 24 | 17 |
| Air Source Heat Pumps | 100 | 23.5 | 73.2 | 17 | 27 | 11 | 24 | 17 |
| Ground Source Heat Pumps | 100 | 24.2 | 75.3 | 18 | 27 | 12 | 25 | 18 |
| **Hot Water System Type** | | | | | | | | |
| Electric Storage Tank | 100 | 105.3 | 327.4 | 77 | 119 | 51 | 109 | 78 |
| Oil-Fired Storage Tank | 100 | 147.1 | 166.9 | 55 | | | | |
| Gas-Fired Storage Tank | 100 | 161.3 | 175.2 | 39 | | | | |
| Electric Heat Pump Tank | 100 | 50.0 | 155.5 | 37 | 56 | 24 | 52 | 37 |
| Electric Instantaneous | 100 | 101.0 | 314.2 | 74 | 114 | 49 | 104 | 75 |
| Gas-Fired Instantaneous | 100 | 122.0 | 132.5 | 29 | | | | |

Space conditioning and hot water heating systems have a broad range of end-use and FFC efficiencies, and the geographic attributes of heating and cooling demands, and how electricity is generated, can dramatically impact overall energy consumption and $CO_2$ emissions. Table 5.3 puts this information together. For 100 MWh of "Useful Energy Demand" — heating or cooling delivered inside the building — the table shows how much retail (site) and primary (source) energy was needed, as well as how much total $CO_2$ was emitted. This information is shown at both the national level and for select NERC regions where emissions are high or low, and there are large heating or cooling seasons.

The results identify the dangers of a "one size fits all" approach. Even moving to generic FFC efficiency and emissions metrics hides important differences. For $CO_2$ emissions, gas-fired furnaces and air-source heat pumps have roughly equivalent $CO_2$ emissions using national averages. When we look at higher emissions NERC regions such as the Southwest Power Pool (SPP), which covers parts of Kansas, Oklahoma, Texas, and neighboring states, the electric-fueled options have substantially higher $CO_2$ emissions. Even ground-source heat pumps (with higher COP efficiencies) result in higher $CO_2$ emissions than the direct use of natural gas in regions where electric sector $CO_2$ emissions are high, such as the Midwest Reliability Organization (MRO). Conversely, in regions where electric power comes from cleaner sources, including natural gas, like the Northeast Power Coordinating Council (NPCC), heat pump systems have better $CO_2$ emissions rates than the direct use of natural gas — although air-source heat pumps may not be applicable throughout the entire Northeast.

**FINDING**

**Use of equipment-based FFC efficiency and national average energy demand and $CO_2$ emissions metrics alone are not sufficient to inform policy makers and consumers of the comparative cost and environmental benefits of competing appliances and building energy systems.**

**RECOMMENDATION**

**More detailed and targeted approaches are needed to develop combined cost- and emissions-effective strategies for meeting future energy and emissions goals on a local and regional basis. State and Federal agencies should collaborate with the building industry and equipment manufacturers to provide clear and accurate information to consumers.**

The findings regarding FFC efficiency, the comparative duty-cycles of space conditioning and other technologies, plus the $CO_2$ burdens of different fuels including regional differences in power generation, identify the need to develop more tailored energy policies for transforming the Residential sector, and by extension, all buildings. This includes total building energy performance and not just FFC efficiencies, cost-effectiveness, and the emissions effectiveness of space conditioning and hot water systems. For policy makers, this should also include local and regional building stock trends, including building retrofits and new construction.

The efficiencies for the best heating, cooling, and hot water technologies are already very high, so thermodynamically we cannot expect much improvement. Therefore, policies affecting RD&D in this area would reasonably focus on manufacturing cost-reductions and local capacity building for "plug-and-play" installation of new systems in both retrofit and new build applications. As mentioned above, this also needs a public education and awareness component focusing on how well various technologies match local conditions, as well as the development of well-trained local practitioners able to specify, install, and maintain cost- and emission-effective building energy systems.

## DEMAND FOR NATURAL GAS AS A TRANSPORTATION FUEL

The Transportation sector poses a dual challenge in a carbon-constrained future. First, the Transportation sector is responsible for about a third of $CO_2$ emissions from the U.S. economy. Second, the Transportation sector is currently almost wholly dependent on oil as a transportation fuel, making it very challenging to reduce those emissions to any significant extent. The concentration of resources in the Middle East, and the large balance of payment deficit created by about 12 million barrels per day (bpd) of U.S. oil imports conspire to make oil use in the Transportation sector a major energy security problem as well. In this section of the chapter, we look at how these two challenges might be tackled, to both reduce the oil dependency of transportation in the U.S. and to reduce the $CO_2$ emissions that go with it.

Natural gas is garnering attention for its potential to address these challenges in an economically attractive way. Natural gas produces significantly less $CO_2$ than oil when combusted. It is also an abundant domestic resource with a price that, on an energy equivalent basis, is substantially lower than that of oil. Consequently, there is the possibility for substantial energy security and environmental benefits to be gained by the penetration of natural gas into the Transportation sector. About 2 Trillion cubic feet (Tcf) of natural gas per year — slightly less than 10% of current U.S. consumption — could displace approximately 1 million bpd — about 5% of current U.S. consumption.

We explore this opportunity in two ways: direct use of compressed natural gas (CNG) and liquefied natural gas (LNG) in vehicles; and indirect use through conversion of natural gas to liquid fuels. The attraction of the indirect pathway is the potential to capitalize on the large-scale liquid fuel infrastructure in place and to use current vehicles or vehicles very similar to those on the road today.

### Global Natural Gas Vehicle Market[32]

There are approximately 11 million natural gas vehicles (NGV) on the road worldwide of which more than 99.9% are operated on CNG, the rest being LNG-powered trucks. CNG vehicles are a small fraction, on the order of 1%, of the close to 900 million vehicles on the road worldwide. The NGV world market is predominately comprised of light-duty vehicles consisting of cars and light trucks (95%), with a smaller number of buses (3%) and trucks (2%). The majority of the light-duty NGVs are bi-fuel vehicles with the ability to operate on CNG or gasoline.

The largest light-duty NGV markets are found in Asia (Pakistan and Iran) and South America (Argentina and Brazil), where government policies support the use of NGVs. Natural gas capable vehicles constitute around 20% of the vehicles in Argentina and 70% in Pakistan. Europe has about one million CNG vehicles whereas there are only approximately 100,000 light-duty CNG vehicles in the U.S.

### CNG-Powered Vehicles

CNG-powered vehicles use spark-ignition engines that are basically the same as those used in gasoline-powered vehicles. They can be factory-produced or aftermarket conversions of gasoline vehicles. The CNG is stored in high-pressure tanks (e.g., at 3,000 psi) to obtain sufficient energy density (fuel energy per volume). Even with storage at high pressure, the range of a CNG vehicle for a given tank size is only about one-quarter that of gasoline. Use of CNG requires a new fueling infrastructure that would require substantial additional investment.

Because of the lower carbon/hydrogen ratio of methane relative to gasoline, the $CO_2$ emissions from the combustion of natural gas are approximately 75% of those of gasoline for a given amount of energy production. Thus, on an energy basis at the point of use, the $CO_2$ emissions are reduced by around 25% relative to the use of gasoline for the same engine efficiency. On a life-cycle basis, this advantage is reduced because the GHG emissions in production and distribution, including methane leakage, are greater for natural gas than for oil products, as discussed in Appendix 1A.[33]

The CNG vehicle market segments in the U.S. that are likely to offer an attractive payback period in the near term involve high-mileage use. These include short-range, heavy-duty vehicles (e.g., urban buses, delivery trucks) and high-mileage, light-duty vehicles, primarily fleet vehicles (such as taxis, and business and government vehicles). These two market segments presently have a total potential (assuming 100% penetration in these segments) of 2.5 Tcf/year — equivalent to 1.3 million bpd. Short-range, heavy-duty vehicles are particularly attractive for CNG because they operate with low mileage per gallon, resulting in substantial fuel cost savings.

**FINDING**

**At present gasoline-CNG fuel price spreads, U.S. heavy-duty vehicles used for short-range operation (buses, garbage trucks, delivery trucks) have attractive payback times (around three years or less).**

**Payback times for U.S. light-duty vehicles are attractive provided they are used in high-mileage operation (generally in fleets) and have a sufficiently low incremental cost — a representative number is around $5,000 for a payback time of three years or less. This condition is presently not met.**

Although CNG is substantially cheaper than gasoline on an energy basis, its use requires significant additional upfront vehicle costs. Thus, a key factor in CNG vehicle market penetration is a sufficiently short time to compensate the higher cost of a CNG vehicle with lower-priced natural gas. In the U.S., incremental costs are high, particularly for aftermarket conversions. The only factory-produced CNG vehicle in the U.S. is the Honda GX, which presently has an incremental cost relative to an equivalent gasoline vehicle of about $7,000, and may be compared to the premium of about $3,700 for the European VW Passat TSI Eco-fuel. The Honda GX offers only natural gas operation and, thereby, has received a tax subsidy not given to factory-produced vehicles providing bi-fuel operation. In contrast, VW Eco-fuel and Fiat vehicles produced in Europe do offer bi-fuel operation, increasing flexibility, which is crucial for non-fleet users.

Aftermarket conversions are available for a wide range of U.S. cars and light trucks, and provide bi-fuel operation. However, costs are approximately $10,000 per vehicle, with firms carrying out the conversions pointing to U.S. EPA certification procedures for the high expense. In contrast, conversions are being provided for around $2,500 per vehicle in Singapore.

**FINDING**

**Experience in other countries indicates the potential for substantial reduction of incremental costs for U.S. factory and aftermarket converted CNG vehicles.**

**Table 5.4 Illustrative Payback Times in Years for CNG Light-Duty Vehicles for Average and High Mileage Use, Low and High Incremental Vehicle Cost, and Fuel Price Spread between Gasoline and CNG on a Gallon of Gasoline Equivalent (gge) Basis. Assumes 30 miles per gallon.**

| | | 12,000 mile per year | | 35,000 miles per year | |
|---|---|---|---|---|---|
| Fuel Price Spread | Incremental Cost | $3,000 | $10,000 | $3,000 | $10,000 |
| | $0.50/gge | 15 | 50 | 5.2 | 17 |
| | $1.50/gge | 5 | 17 | 1.8 | 5.9 |

Source: MITEI

Table 5.4 illustrates the effects of various factors on payback time for light-duty vehicles. The fuel price spread of $1.50/gge shown in the table would be associated with a $3.00/gallon pump price for gasoline and residential gas at the consumer level of $12/MMBtu.[34] Payback time is the incremental cost divided by the yearly fuel cost savings. Studies have shown that payback times of around three years or less are needed for substantial market penetration.[35] For the representative high-mileage use case of 35,000 miles/year, a three-year payback time could be obtained with a U.S. price spread of $1.50/gge and an incremental vehicle cost of around $5,300.

For present CNG vehicle costs and U.S. fuel price spreads, the payback times are generally unattractive for the average mileage use (12,000 miles/year) market segment for light-duty vehicles; this market segment represents over 90% of light-duty vehicle fuel use. Reduction of the incremental cost to below $1,800 along with $1.50/gge fuel price spread would be needed for a three-year payback time. The rate of penetration of average mileage CNG vehicles, even if economic, will depend on the provision of an adequate public refueling infrastructure, though home refueling of CNG vehicles could augment public facilities.

Table 5.4 does not include the effect of a penalty on carbon emissions or a subsidy. For the illustrative case in the table, the use of CNG rather than gasoline reduces $CO_2$ emissions at the vehicle by about 1 ton/year for the average mileage (12,000 miles/year), light-duty vehicle. Even for a $CO_2$ price as high as $100/ton, the impact on payback time is small.

If the gasoline to CNG price spread were to increase beyond the present level, the payback time for the average mileage CNG vehicle could decline and support greater penetration in this large market segment. A significant increase in the spread could occur either through an increased oil-natural gas price spread, a very high $CO_2$ price, and/or availability of natural gas for CNG vehicles at lower than residential rates. Using optimistic cost estimates for CNG vehicles, the carbon policy scenario explored in Chapter 3 projects a 20% penetration into the private vehicle fleet by 2040 to 2050. Recently enacted state low-carbon fuel standards (e.g., California) might provide additional motivation for the market penetration of NGVs.

Evolutionary technology could increase the fuel efficiency of bi-fuel engines by 25% to 30%, providing an efficiency level comparable to a diesel engine.[36, 37] This could increase the value of natural gas in reducing oil dependence and GHG generation. Higher efficiency, natural gas-powered, spark-ignition engines also have the potential to reduce the cost and increase the power of LNG-powered trucks.

**RECOMMENDATION**

**The U.S. should consider revision to its current policies related to CNG vehicles, including how aftermarket CNG conversions are certified, with a view to reducing upfront costs and facilitating bi-fuel CNG-gasoline capability.**

### LNG-Powered Long-Haul Trucks

LNG is being pursued as a fuel for truck applications, particularly long-haul trucking, because for a given tank size, it can provide a range of close to two and half times that of CNG, and around 60% of that of diesel fuel. On the vehicle, LNG is stored at very low temperature (-162°C) in a double-walled tank with a vacuum between the walls to provide thermal insulation. Over time, the LNG warms, the methane gas boils, and eventually a pressure relief valve must be opened if the tank is not refilled within a relatively limited period of time (about a week). This feature constrains the use of LNG to vehicles that have regular frequent refills. LNG is in limited use in the U.S. in drayage trucks in the ports of Long Beach and Los Angeles and in garbage trucks in several cities.

The GHG advantage of LNG is lower than CNG because of the energy loss in liquefaction and methane emissions in fueling and operation. A representative GHG emission reduction relative to diesel for the same engine efficiency is 10% to 15%. As with the CNG-gasoline comparison noted earlier in the chapter, this modest GHG advantage would be substantially reduced or possibly eliminated if stated on a life-cycle basis including the fugitive emissions of methane in production and distribution. Of course, the oil displacement benefits remain.

The current incremental cost of an LNG long-haul truck is around $70,000. Even if the payback time is acceptable (it is about four years at late 2010 natural gas and oil prices), this high incremental cost can be an impediment to market penetration. An additional factor is that the resale value, particularly in the international market where many used trucks are sold, is likely to be substantially reduced. Another challenge may be assuring that reliability will not be adversely affected by operational issues related to cryogenic fuel storage in a tank with vacuum thermal insulation (manufacturing issues, a collision, or extended use may reduce the ability of the tank to store LNG cryogenically). If the integrity of the vacuum is compromised and LNG warms, methane gas boils off, increasing pressure in the tank. The relief valve is used to vent the boiled-off methane and cool the remaining methane. A further challenge is the need for a new fueling infrastructure that is more expensive and complex than the diesel fueling infrastructure.

The American Trucking Association, representing concerns of the user community, has stated that natural gas-powered trucks are currently not a viable solution for most long-haul trucking operations for these technical reasons and because of the concern that the high cost of LNG fueling infrastructure will limit competition in the on-road LNG fuel supply.[38] LNG-powered trucks may also face competition from other alternatives to diesel fuel, such as methanol, as discussed in the next section.

Industry is working on reducing the incremental cost and improving operational features related to the use of a cryogenically stored fuel. It is likely that a significant cost reduction can be made, particularly in the cost of the engine. In addition, use of LNG-powered, long-haul trucks is significantly less challenging in the growing area of transporting goods between company-owned hubs. These hubs could have their own LNG fueling stations. This is a modest market segment which presently accounts for less than 20% of long-haul diesel fuel consumption. It has a market potential (100% market penetration) of less than 0.8 Tcf per year. With increased use of hubs in long-distance trucking and reduced range requirements, there may be opportunities for use of CNG as well as LNG. These opportunities could be enhanced by bi-fuel capability with gasoline as a range extender.

**FINDING**

**The deployment of LNG-powered, long-haul trucks presently faces operational limitations due to the use of onboard fuel storage at very low temperature (-162 C°); the need for a new fueling infrastructure that ensures competitive pricing; a high incremental cost; and a likely lower resale value particularly in the important international market. These challenges are mitigated by use in the relatively modest market of hub-to-hub transport.**

## Conversion to Liquid Fuels

Another route for natural gas penetration into transportation markets could be through conversion into a (room temperature) liquid fuel that could be blended with (or replace) current liquid fuels (diesel, gasoline, and ethanol). As illustrated in Figure 5.9, a range of liquid fuels can be produced from natural gas by thermochemical conversion to a synthesis gas followed by catalytic conversion to the liquid fuel. These fuels include methanol, ethanol, mixed alcohols (methanol, ethanol, and others), and diesel. Methanol can in turn be converted into gasoline or into dimethyl ether (DME), a clean-burning fuel for diesel engines.

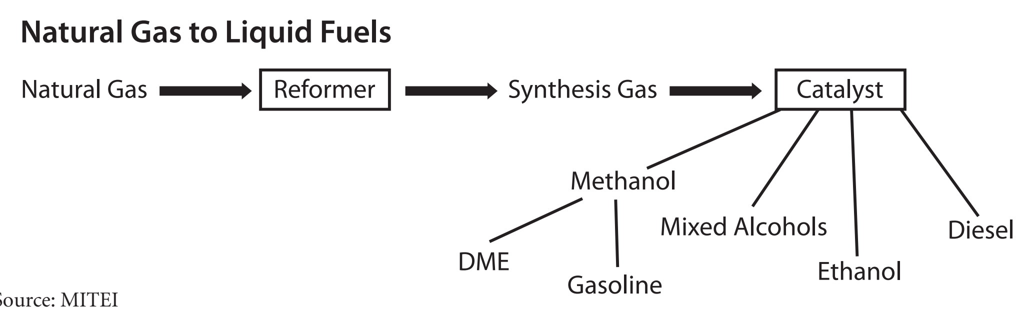
The choices among these multiple pathways to liquid fuels depend on several criteria involving engine requirements and fueling infrastructure. Diesel and gasoline are drop-in fuels with regard to current engine technology and fueling infrastructure, but require more processing from natural gas feedstock than other routes, such as methanol production, making the conversion less efficient and more costly.

Methanol is less costly for conversion, but requires modest changes to engines (it is more corrosive than gasoline) and the fueling infrastructure (methanol and ethanol are hydroscopic) that has been developed for a petroleum-based system. DME requires moderate pressure for storage as a liquid (similar to propane). Overall system optimizations are needed to guide choices.

Our detailed analysis is for natural gas conversion to methanol. There is considerable experience for both conversion to methanol and for use of methanol in vehicles (including high-performance Indy 500 cars). The efficiency of conversion of natural gas into methanol, mixed alcohols, and DME is considerably higher than that for the conversion of natural gas into diesel and gasoline.

Among the processes shown in Figure 5.9, the one that has been operated at large industrial scale over a long period, with well-established costs, is methane-to-methanol conversion, mainly as a feedstock for chemical production.[39] Methanol is an alcohol that can be used like ethanol in mixtures with gasoline in spark-ignition engines and can be employed in heavy-duty as well as light-duty vehicles. With the energy loss during conversion of natural gas to methanol taken into account, the well-to-wheels $CO_2$ emissions from using natural gas derived methanol is slightly lower than gasoline.[40] GHG emissions could be somewhat higher than gasoline if methane emissions are included. The production cost of natural gas conversion to diesel fuel is projected to be around 30% higher than methanol on an energy-equivalent basis. In addition, GHG emissions would be increased by more than 50% relative to natural gas derived methanol.

**Figure 5.9 Conversion of Natural Gas to Liquid Fuels**




Source: MITEI

Methanol used in the U.S. is mainly imported from the Caribbean and South America, at comparable prices over the period 2005 to 2010 to gasoline on an energy-equivalent basis. With deployment of new plants, using existing technology, methanol could be produced from U.S. natural gas at a cost less than U.S. gasoline price in 2010 of around $2.30/gallon (excluding the tax). Table 5.5 shows an illustrative projection of methanol production costs. It is based on a 67% energy conversion efficiency of natural gas into methanol and a contribution of amortized capital and operating costs of $0.50/gge of methanol production.[41, 42] Under these assumptions, the spread between gasoline price and methanol cost is around $1/gge. The cost advantage of methanol at the fueling station is reduced by around $0.10/gge due to higher cost per unit energy of transporting methanol to fueling stations. The production cost of methanol at this assumed natural gas price would be lower than the cost of corn-based ethanol by more than $1.00/gge.[43]

**FINDING**

**With deployment of plants using current technology, on an energy-equivalent basis, methanol could be produced from U.S. natural gas at a lower cost than gasoline at current oil prices.**

Methanol can be used in spark-ignition engines, with very low emissions of NOx and other pollutants through use of state-of-the-art, three-way catalytic converters. It has a high-octane number that enables high-efficiency engine operation. Methanol has the disadvantage of being able to provide only around half of the range of gasoline for a given tank size, which would be mitigated by methanol-gasoline mixtures.

Methanol use was demonstrated in the U.S. in the early 1990s, in some 15,000 vehicles. Interest waned in the mid-1990s, however, due to falling oil prices and the ascendency of ethanol in low-concentration blends, driven by strong political support from the farm states. In addition, aversion to methanol may have developed from its association with MTBE (Methyl Tertiary Butyl Ether), an additive to gasoline that contaminated ground water from leaks in underground tanks and that, unlike methanol, produced an unpleasant taste in water at very low concentrations. The toxicity of methanol is similar to gasoline. Methanol is soluble in water and is biodegradable.[44]

Methanol could be used in tri-flexible-fuel, light-duty (and heavy-duty) vehicles in a manner similar to present ethanol-gasoline flex fuel vehicles, with modest incremental vehicle cost. These tri-flex-fuel vehicles could be operated on a wide range of mixtures of methanol, ethanol, and gasoline. For long-distance driving, gasoline could be used in the flex-fuel engine to maximize range. Present ethanol-gasoline flex-fuel vehicles in the U.S. are sold at the same price as their gasoline counterparts. Adding methanol capability to

**Table 5.5 Illustrative Methanol Production Costs, Relative to Gasoline (excluding taxes) at $2.30 per Gallon**

| Natural Gas Price | Methanol Production Cost, per gge | Cost Reduction Relative to Gasoline, per gge |
|---|---|---|
| $4/MMBtu | $1.30 | $1.00 |
| $6/MMBtu | $1.60 | $0.70 |
| $8/MMBtu | $2.00 | $0.30 |

Source: MITEI

a factory 85% ethanol blend (E85) vehicle, to create tri-flex fuel capability, would require an air/fuel mixture control to accommodate an expanded fuel/air range with addition of an alcohol sensor and would result in an extra cost of $100 to $200, most likely at the lower end of that range with sufficient production.

**FINDING**

**Methanol could be used in tri-flex-fuel light-duty vehicles with a modest incremental vehicle cost (likely to be $100 to $200 more than an ethanol-gasoline flex-fuel vehicle). It could also be used to power long-haul trucks in mixtures with gasoline, and could provide both vehicle and fuel cost savings. Barriers to methanol use include the lack of incentives for vehicle conversion and provision of distribution infrastructure.**

Presently, no factory-produced flex-fuel vehicles in the U.S. are equipped for flex-fuel operation with methanol. Removing this barrier through the adoption of an open fuel standard is a key requirement for methanol use to be pursued on a level playing field. Open fuel standard legislation that has been under consideration would require automobile manufacturers to produce an increasing number of vehicles that could operate on a mix of the three fuels. Requiring this flex-fuel capability could be a cost-effective way to level the playing field for liquid fuels and increase opportunities for reducing oil dependence.

**RECOMMENDATION**

**The U.S. government should implement an open fuel standard that requires automobile manufacturers to provide tri-flex-fuel operation in light-duty vehicles. It should also consider methanol fueling infrastructure subsidies similar to those given to the fueling infrastructure for ethanol.**

Methanol can be used as a fuel for heavy-duty vehicles in a range of mixtures with gasoline. Use of methanol as an alternative to diesel for heavy-duty vehicles is now possible by use of turbocharged spark-ignition engines operating at high compression ratio and high levels of turbo pressure boosting. These engines can provide comparable or possibly better efficiency than diesel engines along with comparable or greater torque, at lower vehicle cost and with lower emissions and more power.[45] An illustrative comparison for a methanol-gasoline mixture of 70% methanol vs. diesel for a long-haul truck suggests a vehicle cost saving of more than $10,000 (from less-expensive exhaust treatment and a less costly fuel-injection system) and a fuel saving of some $5,200/year.[46]

Use of methanol as a transportation fuel faces a number of challenges. They include the financial risk for private investment in U.S. methanol production plants: the demand for methanol as a transportation fuel could be reduced by a decline in oil prices and domestic natural gas prices are volatile. In addition, incentives are lacking for building methanol capability into vehicles and incurring the costs of additional infrastructure, such as pumps in fueling stations. It is likely that some form of government assistance would be necessary to facilitate this option at large scale.

In summary, while use of methanol as a transportation fuel has substantial cost and GHG advantages relative to other natural gas derived liquid fuels, it requires some infrastructure modification and faces substantial acceptance barriers. At sufficiently high oil prices, the drop-in fuel and acceptance advantages of natural gas derived gasoline may make it a better candidate than methanol. Natural gas derived diesel could also become economically attractive.

**FINDING**

**If the present oil to natural gas price spread is sustained, there will be materially increased opportunities for use of natural gas-based transportation fuels.**

**FINDING**

**The potential for natural gas to reduce oil dependence could be increased by conversion into room temperature liquid fuels that can be stored at atmospheric pressure. Of these fuels, methanol is the only one that has been produced for a long period at large industrial scale. Methanol has the lowest cost and lowest GHG emissions, but requires some infrastructure modification and faces substantial acceptance challenges. Natural gas derived gasoline and diesel have the advantage of being drop-in fuels, but carry a higher conversion cost.**

**RECOMMENDATION**

**The U.S. government should carry out a transparent comparative study of natural gas derived diesel, gasoline, and methanol, and possibly natural gas derived ethanol, mixed alcohol, and DME, with each other and with oil-derived fuels and biofuels. The study should include cost analysis, vehicle requirements, infrastructure requirements, and health and environmental issues. It also should include discussion of R&D needs for more-efficient and lower-cost production.**

## NOTES

[1]U.S. Energy Information Administration statistics refer to "Lease and Plant Fuel" as natural gas used in well, lease, or field operations (such as gas used in drilling operations, heaters, dehydrators, and field compressors) and as fuel in natural gas processing plants.

[2]Data derived from the U.S. Energy Information Administration Manufacturing Energy Consumption Survey (MECS), which collects data on energy consumption by industry sector and end use. The MECS historically covers 80% to 90% of total industrial natural gas use. See http://www.eia.doe.gov/emeu/mecs/contents.html.

[3]"Solutions from Shop Floor to Top Floor: Best Business Practices in Energy Efficiency," prepared by William R. Prindle, ICF International, for the Pew Center on Global Climate Change, April 2010.

[4]Energy Information Administration, Annual Energy Outlook 2011. Table A2. See http://www.eia.doe.gov.

[5]AEO 2011, Table A6.

[6]For details see Paltsev, S., et al. (2010), "The Future of U.S. Natural Gas Production, Use, and Trade", MIT Joint Program on the Science and Policy of Global Change, Report No. 186, Cambridge, MA.

[7]U.S. Energy Information Administration, 2008 Manufacturing Energy Consumption Survey.

[8]Industrial boilers are rated in terms of heat input on the basis of MMBTU/hr.

[9]Energy Efficiency in boilers is measured as AFUE or Average Fuel Use Efficiency.

[10]The DOE Energy Efficiency Standards can be found at 10 CFR Part 431.

[11]An overall guidebook is "Improving Process Heating System Performance: A Sourcebook for Industry," published by the U.S. Department of Energy, Industrial Technologies Program and the Industrial Heating Equipment Association. DOE and industry groups also have co-authored a number of industry sector-specific reports on energy efficiency improvements.

[12]Pew Center Report.

[13]Pew Center Report, p80.

[14]See "Energy Star" guides published by Lawrence Berkeley National Laboratory.

[15]"Cutting Carbon and Making Money," Chemical & Engineering News, Volume 88 Number 15, April 12, 2010.

[16]"Ethylene from Methane," Chemical and Engineering News, January 24, 2011.

[17]This process is described more fully in the "Super Boiler White Paper," which can be found at http://www.cbboilers.com/superboiler.

[18]"Energy Research at DOE: Was It Worth It?" National Research Council, 2001, p32.

[19]Reported in the U.S. Department of Energy, FY 2012 Congressional Budget, p 250.

[20]U.S. Energy Information Administration, "Annual Energy Outlook 2011," Table A2.

[21]U.S. Environmental Protection Agency and the Combined Heat and Power Partnership, Catalog of CHP Technologies, 2008.

[22]Tapia-Ahumada, Karen, "Understanding the Impact of Large-Scale Penetration of Micro Combined Heat and Power Technologies within Energy Systems," PhD Thesis, Engineering Systems Division, Massachusetts Institute of Technology, 2011.

[23]Tapia-Ahumada, Karen, "Are Distributed Technologies a Viable Alternative for Institutional Settings? Lessons from the MIT Cogeneration Plant," M.Sc. Thesis, Engineering Systems Division, Massachusetts Institute of Technology, 2005.

[24]See http://www.districtenergy.org/us-district-energy-systems.

[25]See http://www.powergenworldwide.com/index/display/articledisplay/1153798328/articles/cogeneration-and-on-site-power-production/volume-10/issue-6/features/the-district_energy.html.

[26]Tapia-Ahumada, 2011.

[27]DOE/EIA Annual Energy Review 2009 [DOE/EIA-0384(2009) August 2010].

[28]Natural Resources Canada, http://oee.nrcan.gc.ca/publications/infosource/pub/home/heating-heat-pump/asheatpumps.cfm.

[29]Compiled from a variety of sources including the US DOE, EnergyStar, ACEEE, AHRI, and others.

[30]Source Energy and Emissions Factors for Building Energy Consumption, Gas Technology Institute, 2009.

[31]Review of Site (Point-of-Use) and Full-Fuel-Cycle Measurement Approaches to DOE/EERE Building Appliance Energy-Efficiency Standards, National Research Council, 2009 – accessed via http://www.nap.edu/catalog/12670.html. Also, Federal Register Vol. 75, No. 161 Friday, August 20, 2010 – 10 CFR Part 431, Policy for Adopting Full-Fuel-Cycle Analyses Into Energy Conservation Standards Program.

[32]The analysis of CNG and LNG in vehicles draws heavily on P.J. Murphy, "Natural Gas as a Transportation Fuel," MS Thesis, MIT, June 2010.

[33] There is large range of uncertainty of the effect of methane emissions. Within this range of uncertainty, the GHG reduction advantage of CNG relative to gasoline could be reduced from 25% to around 12%.

[34] This interpretation assumes the CNG is not subject to transportation fuel taxes. If current taxes were imposed on an energy-equivalent basis, these assumptions would lead to about a $1.00/gge spread.

[35] Yeh, S. "An Empirical Analysis on the Adoption of Alternative Fuel Vehicles: The Case of Natural Gas Vehicles," Energy Policy, 35(11):5865-5875, 2007.

[36] "Optimized Use of E85 in a Turbocharged Direct Injection Engine," R.A. Stein, C.J. House and T.G. Leone, SAE paper 2009-01-1490, 2009.

[37] L. Bromberg and D.R. Cohn, "Alcohol Fueled Heavy-Duty Vehicles Using Clean High Efficiency Engines," Society of Automotive Engineers (SAE) Technical Paper, SAE 2010-01-2199.

[38] American Trucking Association, Statement submitted to the U.S. Senate Committee on Energy and Natural Resources on the use of natural gas as a diesel fuel substitute, November 10, 2009.

[39] Though volumes are small, methanol is in widespread use in windshield washer mixtures with water, with concentrations as high as 50%.

[40] Pearson, R.J. et al., "Extending the Supply of Alcohol fuels for Energy Security and Carbon Reduction," Society for Automotive Engineers (SAE) Paper 2009-01-2764, 2009.

[41] M. A. Weiss et. al., "On the Road in 2020," MIT Energy Laboratory Report MIT EL-00-003, Oct. 2000, p. 2-6.

[42] R. Abbott et al, "Evaluation of Ultra Clear Fuels From Natural Gas," Conoco Philips, Nexant, and Pennsylvania State University, final report for Department of Energy, 2006.

[43] All these comparisons are dependent on the ultimate tax treatment of methanol fuel or various blends with gasoline. This calculation, which includes the tax, implicitly assumes tax treatment that is roughly equivalent on an energy basis.

[44] L. Bromberg and W.K. Cheng, "Methanol as an Alternative Transportation Fuel for the US: Options for Sustainable and/or Energy Secure Transportation," MIT PSFC report PSFC-RR-10-12, 2010.

[45] L. Bromberg and D.R. Cohn, "Alcohol Fueled Heavy-Duty Vehicles Using Clean High Efficiency Engines," Society of Automotive Engineers (SAE) Technical Paper, SAE 2010-01=2199.

[46] The calculation assumes 65,000 miles per year at 5 miles/gallon and a $0.40 M70-diesel price spread (with $5/MMBtu natural gas) and the same engine efficiency. M70 is 70% methanol and 30% gasoline by volume and has a range of around 0.6x the range of diesel for a given fuel tank size.

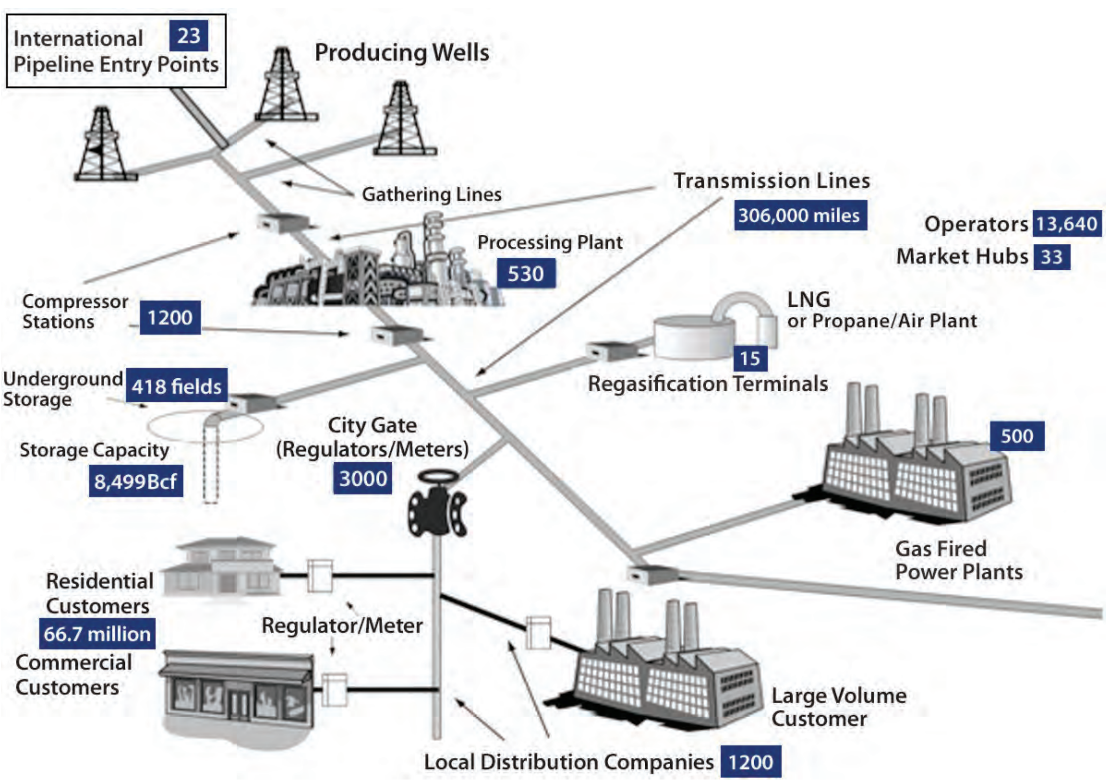
# Chapter 6: Infrastructure

In the United States, the availability, reliability, and price of natural gas are inextricably linked to its production and delivery infrastructure. As seen in Figure 6.1, major components of the system include inter-state and intra-state transmission pipelines, storage facilities, liquefied natural gas (LNG) regasification terminals, and gas processing units, all of which establish the link between gas producers and consumers. This system is both mature and robust.

This chapter will describe and discuss:

- Trends with implications for the U.S. natural gas infrastructure;
- The components and sub-sectors comprising the natural gas infrastructure, with a focus on pipelines, LNG import terminals, processing, and storage;
- New and proposed environmental regulations affecting the natural gas infrastructure; and
- Specific gas infrastructure issues associated with the development of the Marcellus shale.

**Figure 6.1 Schematic of the U.S. Natural Gas Infrastructure**




Source: www.chk.com and MITEI

## TRENDS AFFECTING U.S. NATURAL GAS INFRASTRUCTURE

Several trends are altering the landscape of U.S. gas markets with implications for infrastructure needs and requirements. These include: changing production profiles; shifts in demand/consumption patterns; and the growth of LNG markets.

### Changing Production Profiles

As described in Chapter 2, production from large onshore shale basins is shifting the focus of U.S. production from the Central and Western Gulf of Mexico (GOM), where it has been for the last two decades, back to onshore regions. While GOM production declined by 42% between 2004 and 2008, onshore production in the lower 48 states (L48) increased by 22% over the same time period.[1]

Areas with the most marked production increases include the relatively immature Rocky Mountains, where production increased 103% between 1998 and 2007; and parts of Eastern Texas, where production increased by 177% over the same time period. This shift is expected to be more pronounced as production increases from the Marcellus shale, concentrated in New York and Pennsylvania, with additional production potential in Ohio and West Virginia.

### Shifts in Demand Patterns

There has also been a shift in U.S. gas demand patterns over the last decades, associated in part with relative population shifts to the South and West from the Northeast and Midwest, the two regions in the country where population as a percent of total U.S. population has declined. Population growth has been especially pronounced in the Western U.S., where the population increased by 42% between 1980 and 2008. This growth, coupled with stricter air quality regulations, has led to increased demand for gas in the West, where gas consumption has outpaced population growth, increasing by 68% in the last three decades. In the Northeast, environmental concerns and a shift away from oil in power generation and home heating has led to increased gas consumption; between 1980 and 2008 the population in the Northeast U.S. increased by 19% but gas consumption increased by 50%.[2]

These demand increases, largely for residential, commercial, and electricity uses, have been accompanied by a reduction in demand from industrial customers; this is illustrated by the relative decline in gas consumption in the Southwest U.S., largely Texas, the only region of the country where gas consumption in absolute terms and as a percentage of the U.S. total actually dropped. This 15% decline in consumption over the last three decades can be attributed in part to high natural gas prices over the last several years which drove refineries, and ammonia and other chemical plants offshore.[3]

### The U.S. and LNG Markets

Growing gas demand and significant differences in gas prices between global regions have increased the desirability of a global gas market. As seen in Chapter 3, gas prices are significantly lower under an Emissions Prediction and Policy Analysis (EPPA) scenario where there is a relatively unconstrained global market in natural gas compared to the current regionalized market. While the U.S. represents around 24% of global gas consumption, its engagement in the development of a global LNG market is tempered by dramatic increases in the U.S. producible gas resource base, largely enabled by the affordable production of new unconventional gas resources.

Currently, the U.S. permits proprietary access to LNG suppliers for new regasification terminals; this would allow the developer of a regasification facility to give preference to the import of its own LNG or the LNG of its affiliates at that point of entry.[4] This policy decision was made to incentivize construction of substantial import infrastructure in the U.S., creating opportunities for increased global LNG trade.

## GHG EMISSIONS FROM THE NATURAL GAS INFRASTRUCTURE

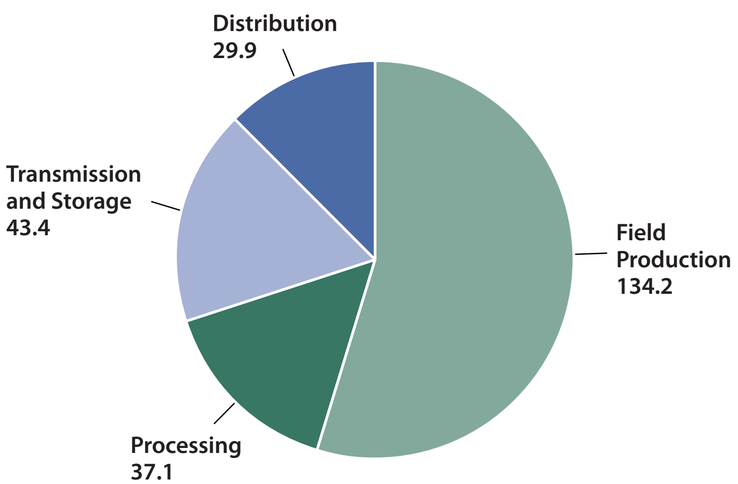
Natural gas is the cleanest burning fossil fuel, enhancing its desirability as a fuel option in a carbon-constrained environment. As a fossil fuel, however, natural gas also emits greenhouse gases (GHG), including carbon dioxide ($CO_2$) emissions from gas combustion and $CO_2$ and methane emissions from the gas system, including production, processing, transmission, and distribution.

According to Environmental Protection Agency (EPA) inventories released in 2010, in 2008 GHG emissions from natural gas systems were 126 teragrams (one teragram is equivalent to one million metric tons) of $CO_2$ equivalents ($CO_2e$), less than 2% of total $CO_2$ equivalent emissions from energy sources and activities. Of this total, 96 teragrams of $CO_2e$ were $CH_4$ emissions; the remainder are from non-combustion $CO_2$. The draft EPA inventory, released in late February 2011, doubled the EPA's estimates of methane emissions from gas systems for 2008. A breakout of EPA's estimated emissions from gas systems is seen in Figure 6.2 (from EPA's revised draft inventory estimates also discussed in Appendix 1A).

Methane leaks from gas systems, particularly at the levels indicated by the new EPA estimates, could prompt efforts to capture those emissions for both environmental and business reasons. Reducing emissions from well completions can, for example, create value for producers and can have a very short payback period (3 to 8 months).[5] While many larger producers and pipelines have already deployed relatively inexpensive methane detection and capture technologies and are able to realize profits from use of these technologies, smaller producers may need new, more affordable technologies to detect and capture methane emissions.

The EPA has also issued a final rule on mandatory reporting of GHG emissions from natural

**Figure 6.2 Estimated $CO_2e$ Emissions from Natural Gas Systems**




Source: EPA Draft GHG Emissions

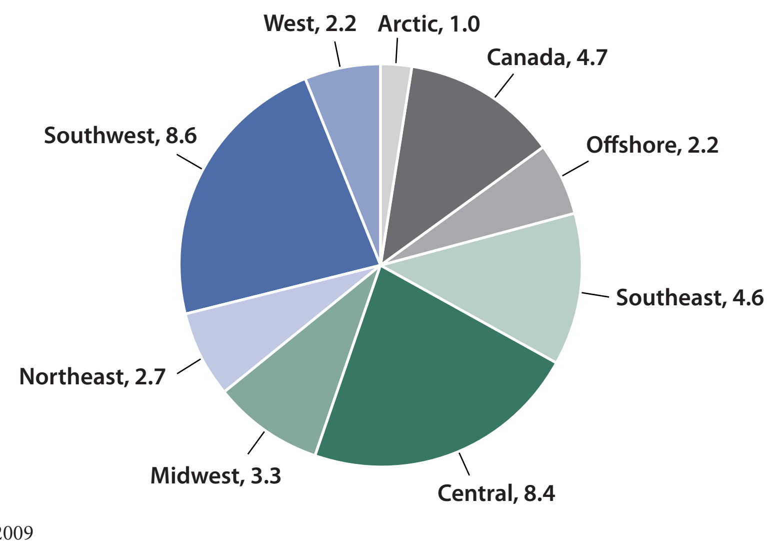
gas systems, after the Supreme Court determined the EPA could regulate GHGs as air pollutants and the EPA issued an endangerment rule in 2010, indicating that GHGs posed a threat to public health and welfare. This rule would require reporting from well pad equipment both onshore and offshore, gas processing, pipelines, city gates, LNG import and export facilities, underground storage, and compressor stations. The rule covers annual reporting of $CO_2$, methane, and nitrous oxide emissions from facilities emitting 25,000 metric tons of $CO_2e$ per year or more. The EPA estimates the cost to the industry of implementing the rule to be $61 million for natural gas and oil systems (the EPA does not separate gas from oil) and $20 million a year in subsequent years in 2006 dollars.

The EPA has deferred direct emitter identification until confidentiality issues can be resolved. All other elements of the rule are now in effect.[6] The EPA estimates that this will affect around 2,800 facilities. The EPA is careful to point out that the 25,000 metric ton limit will exclude small businesses from the requirements of the rule. It is unclear how many small producers would be exempt by the emissions limit. Although the EPA recently postponed deadlines for mandatory emissions reporting, the ultimate regulation of GHGs by the EPA implied in the promulgation of this rule could have major impacts on gas system operations, particularly on production, transmission, and storage, if the estimates in Figure 6.2 are reasonably accurate. The EPA recently extended the deadline for application of best available monitoring methods for gas systems.

## COMPONENTS OF THE NATURAL GAS INFRASTRUCTURE

To move gas from production to demand centers over the next 20 years, it is estimated by the Interstate Natural Gas Association of American (INGAA) that the U.S. and Canada will need approximately 28,900 to 61,900 miles of additional transmission and distribution natural gas pipelines depending on assumptions for gas demand — its base case identifies almost 38,000 miles of pipelines with the regional distribution depicted in Figure 6.3.[7] INGAA also projects a need for 371 to 598 billion cubic feet (Bcf) of additional storage capacity, a 15% to 20% increase over current levels and consistent with the rate of additions between 2005 and 2008.[8]

**Figure 6.3 U.S./Canada Pipeline Capacity Additions, 2009–2030 (in 1,000 of miles)**




Source: INGAA, 2009

**Table 6.1 Total Expected Gas Pipeline, Midstream, and LNG Expenditures, 2009–2030 (billions $)**

| Region | Transmission | Storage | Gathering | Processing | LNG | Total | % |
|---|---|---|---|---|---|---|---|
| Canada | 33.0 | 0.4 | 1.2 | 1.0 | - | 35.5 | **17** |
| Arctic | 24 | - | 1.0 | 3.5 | - | 25.5 | **14** |
| Southwest | 27.6 | 1.3 | 4.2 | 7.5 | 0.4 | 41.1 | **20** |
| Central | 24.8 | 0.2 | 0.7 | 4.8 | - | 30.5 | **15** |
| Southeast | 15.4 | 1.4 | 0.4 | 2.3 | 1.3 | 20.8 | **10** |
| Northeast | 10.1 | 1.0 | 2.3 | 1.6 | - | 15.1 | **7** |
| Midwest | 12.9 | 0.4 | 0.2 | - | - | 13.4 | **6** |
| Western | 8.7 | 0.5 | 0.1 | 1.0 | - | 10.4 | **5** |
| Offshore | 6.3 | - | 7.8 | - | - | 14.1 | **7** |
| Total | 162.8 | 5.2 | 18.0 | 21.7 | 1.8 | 209.5 | **100** |
| **Percentage** | **78** | **2** | **9** | **10** | **1.0** | **100** | |

Source: INGAA, 2009

There will also be additional requirements for gas processing, especially in light of the changes in production patterns in the U.S. Investment requirements by sector for gas infrastructure between now and 2030 are summarized in Table 6.1.[9] Note that these figures assume success in bringing arctic gas to the L48 from Alaska and the Mackenzie delta; the Alaska gas pipeline has remained illusory for the last two decades and its realization remains uncertain.

There are several Federal and state agencies involved in siting gas pipelines and other gas infrastructure. The Federal Energy Regulatory Commission (FERC) regulates interstate pipeline construction while states regulate intra-state pipeline construction. Other Federal agencies play significant roles in construction permitting, including the EPA, the Fish and Wildlife Service, and the Office of Pipeline Safety (OPS) at the Department of Transportation (DOT); the OPS regulates the safety of pipeline operations over the infrastructure's lifespan, starting with up-front safety certifications for permitting by FERC. The EPA ensures that a pipeline development project meets Federal environmental guidelines. The Coast Guard and Maritime Administration (MARAD) at the Department of Homeland Security have responsibility for offshore LNG facilities. In addition to these Federal agencies, there is a range of state entities involved in the permitting process.

The long lead times required to site and build gas infrastructure, driven in part by these complex regulatory decision-making structures for gas infrastructure siting, not only add to the cost, but mean that many of the additions and expansions we are seeing today were originally contemplated as much as a decade ago. This highlights the ongoing tension between the needs of policy makers and regulators for more accurate data and information on supply and demand trends and patterns, the associated infrastructure needs, and the status of technology development; and the inherent uncertainties and risks that accompany investment in natural gas infrastructure across the supply chain.

### The U.S. Natural Gas Pipeline Network

The U.S. natural gas pipeline network includes:

- Gathering pipelines at, or adjacent to, production sites;
- Inter-state and intra-state transmission pipelines which move processed gas over long distances from production sites to major centers of demand; and
- Smaller diameter distribution pipelines, which carry natural gas on to end users.

*Major changes in U.S. gas markets have prompted significant additions to the U.S. pipeline network over the last several years. Between 2005 and 2008, pipeline capacity additions totaled over 80 Bcfd, exceeding those from the previous four-year period by almost 100%.*

In this discussion, we focus largely on transmission pipelines additions, although safety, which is briefly discussed, is also an important issue for distribution pipelines and to some degree, for gathering pipelines as well.

**Pipeline Additions.** Major changes in U.S. gas markets have prompted significant additions to the country's pipeline network over the last several years. Between 2005 and 2008, for example, pipeline capacity additions totaled over 80 billion cubic feet per day (Bcfd), exceeding those from the previous four-year period by almost 100%. Additions of 44.5 Bcfd in 2008 alone exceeded total additions in the five-year period between 1998 and 2002. The rate of additions in 2009, while slower than in the previous several years, was still brisk with 3,000 miles of pipelines added. Figure 6.4[10] highlights major inter-state pipeline additions over the 11-year period from 1998 to 2008.

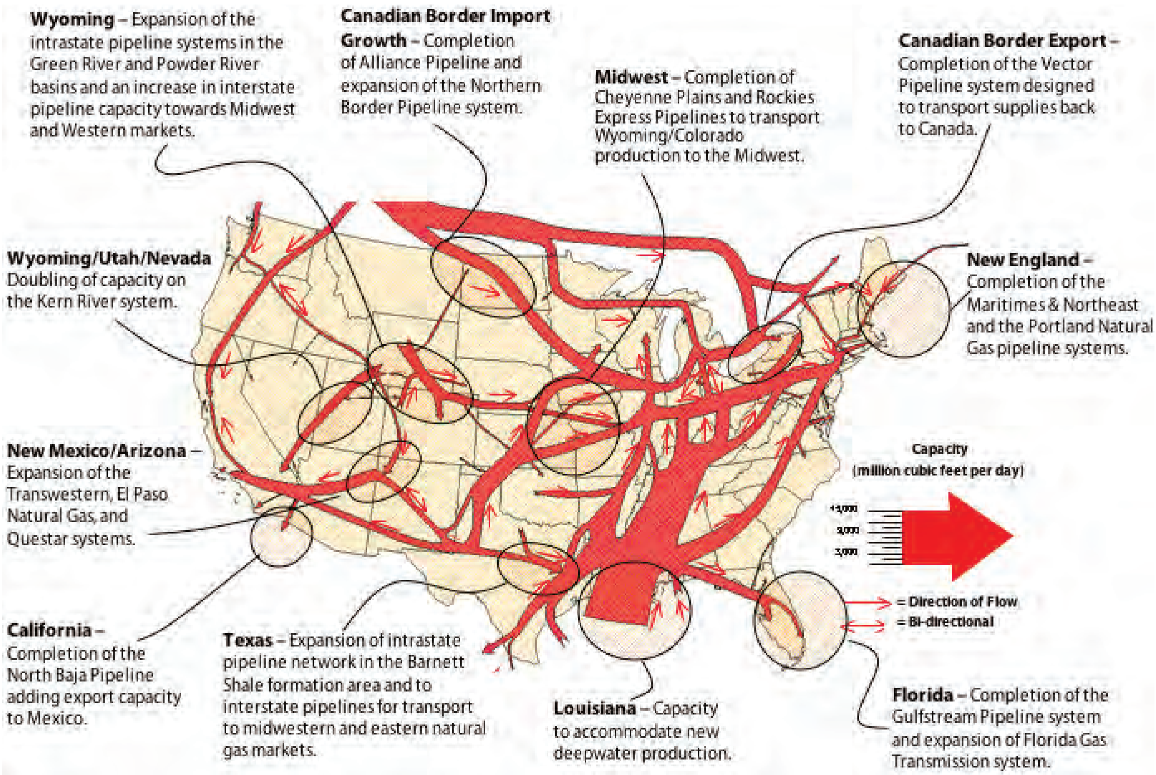
The largest single addition to the pipeline system between 2005 and 2008 was the Rocky Mountain Express pipeline (REX) with a capacity of 1.8 Bcfd. This pipeline has effectively linked Western producer markets to Eastern consumer markets. Other notable additions include Gulf Crossing (1.4 Bcfd) and Midcontinent Express (1.2 Bcfd), both taking gas from the shale regions in Texas and Oklahoma to Alabama and Mississippi; and two expansions to move gas into the Southeast U.S., the 1.6 Bcfd Gulf South Southeast Expansion; and the 1 Bcfd Southeast Supply header.[11]

The largest regional capacity increase in this time frame was from the Southwest region to the Southeast, where almost 6.7 Bcfd of pipeline capacity was added, in part to move shale supplies to markets. Capacity to move supply from the Midwest to the Northeast increased by 1.5 Bcfd, a 30% jump, followed by exports from the Central to Western U.S., at 1.4 Bcfd.

West-to-East expansions are contributing to major changes in the general direction of pipeline flows in the U.S., which have historically moved from south to north. 2030 forecasts suggest the need for an additional 20% of interregional transport capacity.[12] While forecasts and historical pipeline expansions offer a portrait of a robust and adequate response to growth in gas demand, the potential for large increases in gas-fired power generation, either for fuel substitution from gas to coal or as firming power for intermittent renewable generation, could increase the need for gas pipeline infrastructure.

Figure 6.4 depicts total pipeline capacity and directional flows; the circled areas highlight additions between 1998 and 2008, with volumes added and directions indicated by the key in the lower right-hand corner.

## Figure 6.4 Major Additions to Natural Gas Transportation Capacity 1998–2008




Source: Presentation of James Tobin, EIA, Major Changes in Natural Gas Transportation Capacity, 1998–2008, November, 2011.

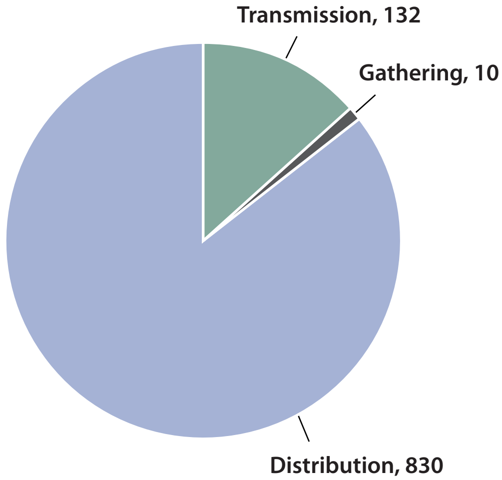
*West-to-East expansions are contributing to major changes in the general direction of pipeline flows in the U.S.*

In Chapter 4 we discuss the need for increased gas peaking units to firm intermittent renewable generation even though their capacity factors would most likely be very low. Similarly, recent analysis by the INGAA Foundation suggests that in the event of large-scale penetration of intermittent renewable generation, gas pipelines may need to dedicate firm capacity to provide service to backup generators even though this capacity would be used infrequently and the per-unit cost of the infrastructure is likely to be very high.[13] The INGAA study also forecasts an incremental delivery capacity requirement of around 5 Bcfd of gas for new firming generation though utilization would be only around 15%, with implied transportation costs that could be around six times more than full-rate utilization costs.[14]

**Pipeline Safety.** Recent gas pipeline explosions in California and Pennsylvania, which caused loss of life and property, underscore pipeline safety as an ongoing issue. There is a range of reasons for pipeline accidents, from pipeline/construction defects to third-party accidents to corrosion. Figure 6.5 shows the number of incidents by type of pipeline over the last 20 years. According to statistics compiled by the DOT, corrosion is the most common cause of leakage for transmission pipelines, and third-party excavation incidents are the most common cause of leakage for distribution pipelines.[15] Leakage is responsible for most serious incidents.

The DOT's Pipeline and Hazardous Materials Safety Administration (PHMSA) has the primary Federal responsibility for ensuring gas pipeline safety. In 2003, the PHMSA implemented a rule that required an integrity management program (IMP) for transmission

**Figure 6.5 Serious Gas Pipeline Incidents by Pipeline Type, 1991–2010**




Source: PHMSA

*Existing pipeline safety research programs within the Federal government and within industry are small and the task of ensuring the integrity of the 306,000 miles of transmission pipelines and 1.2 million miles of distribution pipelines is enormous and essential.*

pipelines. This rule required operators to test transmission pipeline integrity in highly populated areas by 2012. Between 2003 and 2009, after the implementation of the rule, there were six total fatalities; tragically, there were 10 fatalities in 2010 from the explosion and fire in San Bruno, California.

As noted, distribution pipelines are responsible for the largest number of serious gas pipeline safety incidents. Distribution pipelines also pose more difficult problems for integrity management compared to transmission pipelines as they are much smaller in diameter, are shorter, include a significant amount of plastic pipe, and have major branching of pipes to serve end-use customers. A PHMSA rule for distribution pipelines, which went into effect in February 2010, requires IMPs to be implemented by August 2011. While plans are required, they will reflect the different challenges of distribution pipeline safety compared to transmission pipelines; they will likely be less prescriptive and will also cover the operator's entire area, compared to the requirements for transmission pipelines to cover only "high consequence areas."

The DOT has noted the lack of incentives for distribution pipeline operators to assess the safety of distribution pipelines, writing that "…there are no robust market signals or incentives to prompt operators to thoroughly assess the condition of the pipelines or to implement integrity management programs."[16] Also, according to the U.S. Department of Energy's (DOE) Office of Fossil Energy almost one-quarter of U.S. gas pipelines are more than 50 years old.[17] In addition, demand for natural gas is expected to increase over the next couple of decades.

Finally, existing pipeline safety research programs within the Federal government are small and the task of ensuring the integrity of the 306,000 miles of transmission pipelines and 1.2 million miles of distribution pipelines is both large and essential. The PHMSA identifies $33.25 million in Federal funding for pipeline

**Table 6.2 PHMSA Technology Research 2002–present (millions $)**

| Category | PHMSA | Industry | Total |
|---|---|---|---|
| Damage Prevention | $2.79 | $2.33 | $5.12 |
| Pipeline Assessment and Leak Detection | $25.08 | $32.77 | $57.86 |
| Defect Characterization and Mitigation | $0.80 | $1.20 | $2.00 |
| Improved Design, Construction and Materials | $4.58 | $5.40 | $9.98 |
| **Grand Totals:** | **$33.25** | **$39.37** | **$72.62** |

Source: PHMSA Web site

safety technology development since 2002, around $4 million per year (Table 6.2). The PMHSA also identifies $16.94 million in "strengthening standards" research and $29.98 million in "knowledge document" research; the last two categories could be characterized as "regulator's science."

IMPs are necessary but may not be sufficient to meet safety needs. The gas industry noted the need for additional transmission and distribution R&D in a 2007 report.[18] Specific focus areas could include:

- Improving the monitoring and assessment of system integrity;
- Enhancing system flexibility and throughput and reliability;
- Reducing the incidence and cost of subsurface damage;
- Improving the capability of cost-effective construction, maintenance, and repair; and
- Improving data quality and timeliness for system, operation, planning, and regulatory acceptance and mitigating environmental issues.[19]

**Pipelines and Regional Prices.** With respect to pipelines and regional prices, in general, the difference between daily prices at regional hubs compared to Henry Hub prices (the market center in Louisiana that serves as the price point for New York Mercantile Exchange (NYMEX) futures contract) is the basis differential or "basis." The basis differentials are often small, reflecting the short-run variable cost of transporting gas or of displacing shipments of gas to one market center instead of another. Occasionally, when transportation bottlenecks are long term, the basis differentials become large and reflect the different prices at which demand is being rationed in the different locations.

A differential that greatly exceeds the cost of transportation suggests system bottlenecks. According to FERC, Rockies tight gas and Marcellus shale will compete with traditional supplies from the Gulf of Mexico. FERC anticipates that this new supply will help moderate severe basis spikes on peak demand days in the winter.[20]

The relationship of the price differential to infrastructure is observed in the basis differentials at the Cheyenne and Algonquin hubs before and after the opening of the REX pipeline, which is now moving gas supplies from the region to Eastern markets (Figure 6.6). These fairly dramatic changes demonstrate how alleviating pipeline infrastructure bottlenecks can incentivize production and lower consumer prices overall.

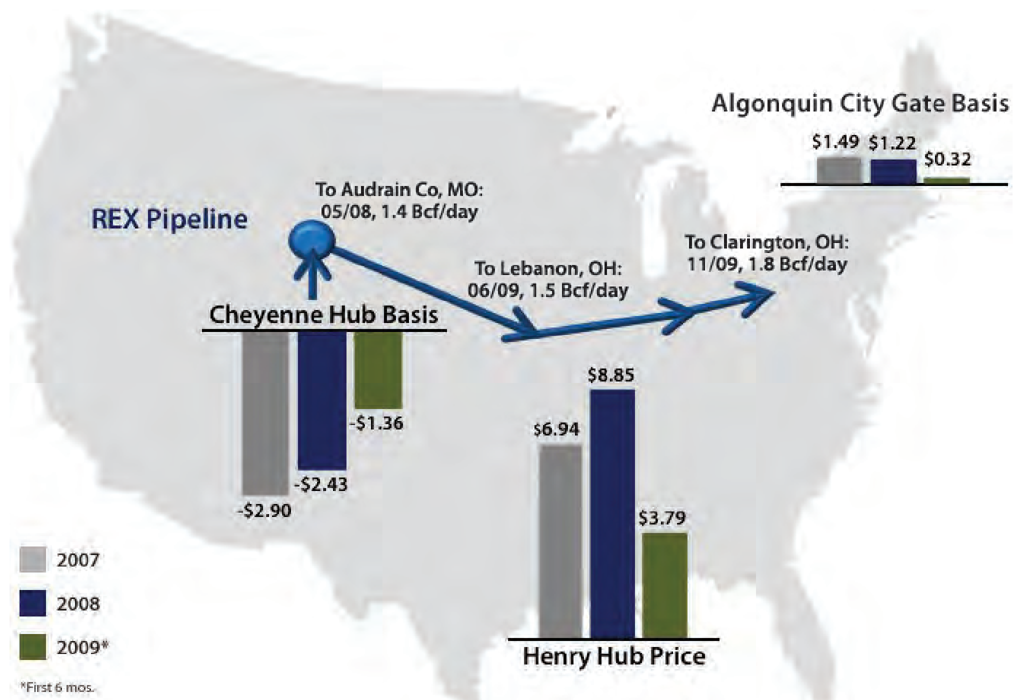
*…alleviating pipeline infrastructure bottlenecks can incentivize production and lower consumer prices overall.*

Before the construction of the REX pipeline, natural gas transportation out of the Rockies region was very constrained, leading to lower gas prices than those at most of the other natural gas market centers. As of November 2009, REX had the capacity to move 1.8 Bcfd of natural gas from the Rockies to Ohio, then to the Northeast. As noted, REX was the largest addition in the U.S. pipeline system between 2005 and 2008 and has effectively joined Western producer markets with eastern consumer markets, a long-time goal of Rocky Mountain producers. This pipeline has had a major impact on gas flows in the Midwest and has reduced the basis differential at both the Algonquin and Cheyenne hubs.

### Natural Gas Processing

Each year in the U.S. some 530 natural gas processing plants process around 16 trillion cubic feet (Tcf) of raw natural gas. These facilities have an average capacity factor of around 68%. Natural gas often requires processing because gas in its raw form can contain impurities which may include sulfur, $CO_2$, water

**Figure 6.6 Impacts of 2008 Pipeline Capacity Expansion on Regional Prices and Average Basis**




Source: Bentek, Beast in the East, 2010

and other contaminants that need to be removed before transport through pipelines to demand centers. Removing impurities such as sulfur, $CO_2$, and water to produce pipeline-quality gas is the primary role of such processing facilities.[21] Understandably, gas processing units are largely located in gas-producing regions of the country. Currently, around 82% of gas-processing capacity is in six states: Louisiana, Texas, Wyoming, Kansas, New Mexico, and Oklahoma.

As noted, gas production is increasing dramatically and production patterns in the U.S. are changing. The need for gas processing additions is likely to be more pronounced in regions where gas production is relatively immature, such as in the Uinta Basin of Eastern Utah and the Piceance Basin of Western Colorado. Gas processing is very limited in the Marcellus Shale Basin where, for example, Western Pennsylvania and Northern West Virginia combined have 530 million cubic feet (Mmcf) of processing capacity, with 435 Mmcf of planned processing additions and a new 37,000 bpd fractionation plant.[22]

Gas processing units also produce natural gas liquids (NGLs) from heavier hydrocarbons contained in unprocessed "wet" gas. If there are sufficient quantities of NGLs, the market conditions are right, and the processing facility has the capacity to both treat and separate NGLs from gas streams, consumer products can be produced, including ethane, propane, butane, and pentanes. These products can add value for gas producers, especially important in a low gas price environment. In 2009, the U.S. gas industry produced 714 million barrels of NGLs, a 16% increase over the 2005 levels of production.

### Natural Gas Storage

Natural gas is stored in underground storage facilities to help meet seasonal demand fluctuations, accommodate supply disruptions, and provide operational flexibility for the gas system, including power plants. Gas storage is also used to hedge price variations.

There are around 400 storage facilities in the L48 owned by 80 corporate entities and managed by 120 operators. Depleted reservoirs account for most storage facilities (82%), followed by aquifers (9%), with salt caverns making up the remainder. Working gas storage capacity nationwide in 2009 was around 4.2 Tcf, which represents about 20% of annual gas production. Over 53% of this capacity is found in just five states: Michigan, Illinois, Louisiana, Pennsylvania, and Texas.[23]

There has been a great deal of interest in the relationship between storage and short-term price volatility. In 2005, the FERC chairman noted that gas storage capacity had increased only 1.4% in almost two decades, while U.S. natural gas demand had risen by 24% over the same period, and speculated that there was a link to the record levels of price volatility that were being experienced.[24] In 2006, FERC issued Order 678 which, among other things, sought to incentivize the building of more storage by changing its regulations on market power requirements for underground storage. Since the order was issued, total storage capacity has increased by 169 Bcf, or 2% of overall storage capacity. This compares to a 1% increase in the previous three-year period.

There is also growing interest in high-deliverability gas storage. Storage facilities are classified as either baseload or peakload facilities. Baseload storage facilities, most often in depleted reservoirs, typically support long-term seasonal requirements primarily for commercial, residential, and industrial customers. These facilities are large and are designed to provide steady supply over long periods of time; their injections (typically over 214 days, April to Oct) and withdrawals (151 days, Nov to Mar) are slow.[25]

*[The] growing relationship between the gas and power infrastructures is highlighted by the increased need for high-deliverability gas storage to match the growth in gas-fired power generation associated with fuel. The degree to which this interdependency stresses both the gas and power infrastructures and creates conditions where the infrastructures and related contracting, legal, and regulatory structures may be inadequate is not fully understood.*

The operational characteristics of baseload storage may be inadequate as storage needed for gas-fired power generation where gas demand varies greatly, not just by season but daily and hourly. Managing this variability is especially important, for example, when, as seen under the carbon price scenario in Chapter 2, natural gas becomes a more critical component of the generation mix. Also, gas peaking units serve as backup for intermittent renewables which may have relatively low load. This type of demand also requires greater variability in storage withdrawals than is found in baseload storage units.

High-deliverability storage provides an option for handling high-demand variability associated with an increased role or natural gas in power generation.[26] High-deliverability storage, typically in salt caverns, is only about 5% of overall gas storage, although capacity increased 36% between 2005 and 2008, compared to 3% for all gas storage.[27] More important than capacity, however, is the withdrawal period. Table 6.3 highlights the much shorter, multicycle capabilities of salt formation storage facilities compared to depleted reservoirs and aquifer storage.[28]

Salt caverns are typically located in the Gulf Coast region and are not found in many areas of increased gas demand, where geology limits both baseload and peakload storage options; this is particularly true in the Northeast, the West (areas of high gas demand for power generation), and parts of the desert Southwest.

The growing use of natural gas for power generation, including the potential near-term displacement of coal with Natural Gas Combined Cycle (NGCC) generation and increased penetration of intermittent renewables, discussed in detail in Chapter 4, underscores the growing interdependencies of the gas and electric infrastructures. This growing relationship between gas and power infrastructures is highlighted by the increased need for high-deliverability gas storage to match the growth in gas-fired power generation. The degree to which this interdependency stresses both the gas and power infrastructures and creates conditions where the infrastructures and related contracting, legal, and regulatory structures may be inadequate is not fully understood.

**Table 6.3 Gas Storage Facility Operations**

| Type | Cushion Gas | Injection Period (Days) | Withdrawal Period (Days) |
|---|---|---|---|
| Depleted Reservoir | 50% | 200–250 | 100–150 |
| Aquifer Reservoir | 50%–80% | 200–250 | 100–150 |
| Salt Cavern | 20%–30% | 20–40 | 10–20 |

Source: FERC Staff Report

**RECOMMENDATION**

**A detailed analysis of the growing interdependencies of the natural gas and power generation infrastructures should be conducted. This should include analysis of the system impacts of increased use of natural gas for power generation and the degree to which this stresses the infrastructure or creates conditions where storage may be inadequate to meet power generation needs.**

### LNG Infrastructure

LNG regasification terminals are the last link in a long supply chain that enables international trade in natural gas and U.S. LNG imports. In 2000, the U.S. had four LNG regasification facilities with a combined capacity of 2.3 Bcfd.[29] High natural gas prices in the first decade of the 21st century, coupled with concerns about declines in domestic supplies and reserves, sparked a wave of construction of new LNG regasification terminals and expansions of existing ones. North America now has 22.8 Bcfd of LNG regasification-rated capacity either operating or under construction (with original planning expectations of capacity factors of around 50%), 89% of which is in the U.S.

These facilities are expensive. The EIA estimated in 2003 that a typical new regasification terminal would cost $200 to $300 million for a sendout capacity from 183 to 365 Bcf (3.8 to 7.7 million tons) per year of natural gas but acknowledged a wide variation in cost, which is very site specific. [30]

In 2009, U.S. consumption of imported LNG was 1.2 Bcfd, leaving most of this new capacity unused and the investment stranded. Demand is, however, geographically uneven. The Everett import facility in Boston, for example, meets around half of New England's gas demand. Gulf Coast terminals however have been forced to seek authorization to re-export gas.[31] On a positive note, the large excess of import capacity provides options for supply diversity in the event of unexpected shortfalls in indigenous supply. Also, LNG supplies initially intended for U.S. markets have been diverted to other countries, with European importers and consumers, including some key U.S. allies, as the main beneficiaries.

**Federal Policy and LNG.** During the last decade, Federal policy facilitated the expansion of LNG import capacity. In 2002, as already noted, FERC issued the so-called Hackberry decision which aided investment in LNG import capacity by allowing LNG developers proprietary access to import facilities. To address delays in LNG import terminal siting associated with jurisdictional conflicts, the Energy Policy Act of 2005 granted FERC exclusive jurisdiction over permitting of onshore LNG regasification facilities, clarifying Federal primacy in this process. Later that year, FERC, in an effort to expedite siting of LNG facilities, established mandatory pre-filing procedures designed to help resolve National Environment Policy Act (NEPA) and other community issues prior to the filing of a formal application with FERC by the developer to site a regasification facility.[32] These statutory and regulatory actions helped enable the permitting of substantial additional regasification capacity in the U.S. Together with additional volumes from Canada and Mexico, 48.65 Bcfd was licensed to supply U.S. markets (but not all of this capacity was built).

These actions by FERC and other agencies illustrate a willingness on the part of the Federal government to expedite the building of energy infrastructure in order to achieve a policy objective; in this instance, adequate and affordable supplies of natural gas were deemed to be in the public interest as it was widely believed at the time that North American gas production had peaked and that imports would be necessary to affordably meet demand.

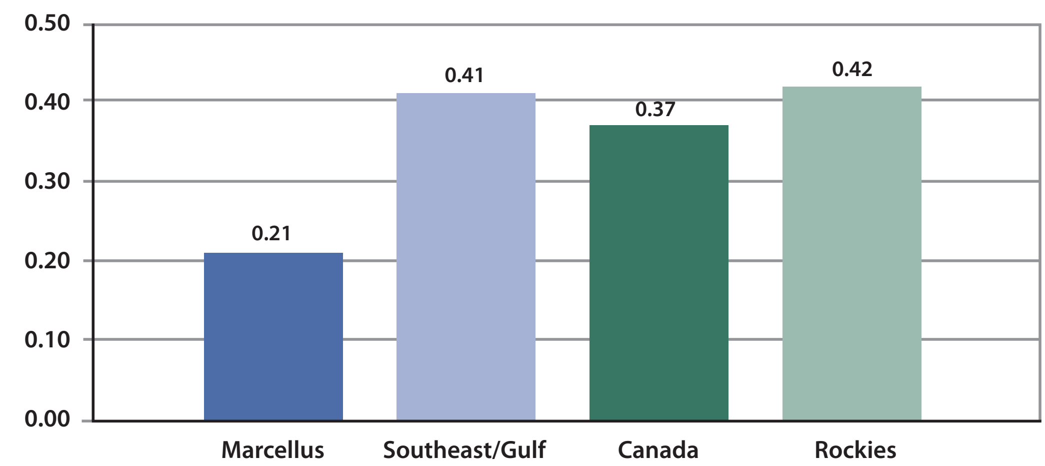
This unused capacity has prompted facility owners and investors to explore opportunities for using them as export as well as import terminals; this would require the building of substantial new liquefaction infrastructure. Cheniere, the owner of the Sabine regasification facility, for example, has entered into non-binding agreements with two potential purchasers of LNG volumes, and is seeking funding to build four LNG trains at the site. The U.S. DOE recently approved a permit for export of LNG from this project to free trade agreement countries only and FERC has initiated an environmental review of the proposal. Others such as Dominion at Cove Point are reviewing export opportunities as well.

## INFRASTRUCTURE NEEDS AND THE DEVELOPMENT OF THE MARCELLUS SHALE

As noted in Chapter 2, the natural gas production profile of the U.S. has been altered by the ability to produce natural gas from large U.S. shale basins. The Marcellus shale may be the largest contiguous shale basin in the world, underlying significant acreage in New York, Ohio, Pennsylvania, and West Virginia, but it is also the least developed of major U.S. shale basins. These Northeastern and Midwestern states are generally more densely populated and less accustomed to natural gas production than Texas, Oklahoma, Arkansas, and Louisiana, the locations of other major producing shale basins. Production in these other basins will continue to alter U.S. gas supply forecasts regardless of the development of the Marcellus. Its sheer size, its under-development, its unique environmental issues, and its proximity to major demand centers and the associated consumer benefits warrants a brief discussion of some key infrastructure issues affecting the development of the Marcellus.

The economics of shale production and the size of the Marcellus shale basin have created enormous interest in the development and production of this vast resource. The location of Marcellus production in the Northeast, with the resulting lower transportation costs to this market, could translate into lower gas prices for the region's consumers, who have typically relied on LNG imports, and Canadian and GOM gas via pipeline.

**Figure 6.7 Average Transportation Costs to Northeast Markets ($ per MMcf)**




Source: Bentek, Beast in the East, 2010

It could also shift GOM gas movements to the southeast, an attractive option for the region's consumers who are on the high-priced end of the Western coal supply chain. Figure 6.7 shows the average and typical transportation costs for producing regions supplying Northeast markets.[33]

The Marcellus, however, needs substantial infrastructure additions to move its gas to markets. There are three transmission pipelines to serve the region either under construction or certified for construction with a combined capacity of over 1 Bcfd, and another 4.8 Bcfd of planned additions to existing pipelines. These additions are essential: Marcellus producers estimated that, as of early 2010, less than half of the 1,100 wells drilled in the Pennsylvania Marcellus had pipeline access.[34]

It is expected that planned investments in pipelines, which are in the several billion dollar range, will also drive investments in underground storage. This is critical for the region as the geology of the Northeast precludes significant storage in this key demand region, which could create a storage bottleneck when moving gas from points West to Northeastern markets, particularly in the peak demand months in the winter.

There is also wet gas in the Marcellus, particularly in Southwestern Pennsylvania. The condensate and NGLs from wet gas enhance the economics of production, assuming favorable market conditions and adequate infrastructure to move NGL products to markets. A significant percentage of this wet gas in the Marcellus requires processing to provide pipeline quality gas. The shortage of processing capacity and outlets for wet gas products could place constraints on the production of pipeline quality gas, and could effectively shut-in significant gas production in the Marcellus. If all planned gas processing capacity additions for the Marcellus were to come on-line, on schedule, the region would have 800 million cubic feet per day (Mmcfd) of gas processing capacity by 2012. Also, two NGL pipeline projects have been proposed from Pennsylvania to Chicago and Ontario which could ease the pressure for NGL outlets. Planned pipeline expansions appear to be adequate.

*Minimizing flowback water, on-site treatment options, water re-use, and new local and regional water treatment facilities are all necessary in managing the environmental impacts of flowback and produced water, water transport, and the stress on existing water treatment facilities in the region.*

Finally, of major interest and concern is the development of a water disposal infrastructure to mitigate the environmental impacts associated with wastewater from drilling which includes flowback water and produced water. Water disposal options in the Marcellus are limited. Strict regulations and complicated geology, particularly in Northeast Pennsylvania, limit the development of disposal wells close to drilling sites. There is extremely limited pre-treatment capacity in the region and the climate is not conducive to evaporation options. Minimizing flowback water, on-site treatment options, water reuse, and new local and regional water treatment facilities are needed to reduce the environmental impacts of flowback and produced water and water transport.

## NOTES

[1]EIA, Table 5a, U.S. Gas Supply, Consumption, and Inventories.

[2]EIA, U.S. Census data.

[3]Bernstein Research report, Natural Gas: Method in the Madness, February, 2009.

[4]CRS Report, Liquefied Natural Gas (LNG) in U.S. Energy Policy: Issues and Implications, May 2004, the so-called "Hackberry decision", "…allowed terminal developers to secure proprietary terminal access for corporate affiliates with investments in LNG supply." Terminals that existed at the time of the ruling in 2002 were exempted. Congress codified Hackberry in the 2005 Energy Policy Act.

[5]EPA Methane to Markets presentation, International Workshop on Methane Emissions Reduction Technologies in the Oil and Gas Industry, Lake Louise, 14-16 September 2009.

[6]See EPA Web site, *Petroleum and Natural Gas Greenhouse Gas (GHG) Reporting Rule (40 CFR Part 98)*, EPA Climate Change Division.

[7]http://www.ingaa.org/cms/15.aspx, Dec 17 2009, 38,000 is base case for gas demand.

[8]http://www.ingaa.org/cms/15.aspx, Dec 17 2009, ranges represent high and low cases in forecasts.

[9]Ibid, high gas demand case.

[10]November 2008, Presentation of James Tobin, EIA, *Major Changes in Natural Gas Transportation Capacity, 1998–2008.*

[11]Bentek, The Beast in the East: Energy Market Fundamentals Report, March 19th, 2010.

[12]Ibid.

[13]INGAA Foundation study, *Firming Renewable Electric power Generators: Opportunities and Challenges for Natural Gas Pipeline*, March 16, 2011.

[14]Ibid.

[15]Serious incident is defined on PHMSA Web site as an event involving a fatality or injury requiring hospitalization.

[16]PHMSA-Research and Special Programs Administration, U.S. Department of Transportation Web site, 2004-19854.

[17]See DOE Fossil of Energy Web site, *Transmission, Storage, and Distribution program description*, as of January 23, 2009.

[18]American Natural Gas Foundation study, *Research and Development in Natural Gas Transmission and Distribution*, March 2007.

[19]Ibid.

[20]FERC Northeast Natural Gas Market, Overview, and Focal Points.

[21]EIA report, Natural Gas Processing: the Crucial Link Between Natural Gas Production and Its Transportation Market, January, 2006.

[22]Bentek, The Beast in the East: Energy Market Fundamentals Report, March 19th, 2010.

[23]EIA Table 14, Underground Storage Capacity by State, December 2009.

[24]December 15, 2005, Statement by FERC chairman Joe Kelliher on the Notice of Proposed Rulemaking Announcement on Natural Gas Storage Pricing Reform.

[25]FERC Staff Report, *Current State of and Issues Concerning Underground Natural Gas Storage*, 2004.

[26]INGAA Foundation Web site notes that, "additional conventional storage will be needed to meet growing seasonal demands and high deliverability storage will be required to serve fluctuating daily and hourly power plant loads."

[27]EIA, Table Underground Natural Gas Storage by Storage Type.

[28]FERC Staff Report, *Current State of and Issues Concerning Underground Gas Storage*, 2004.

[29]Gas Technology Institute, LNG Sourcebook, 2004.

[30]EIA Report #:DOE/EIA-0637, December 2003.

[31]FERC report, *State of the Markets*, 2009.

[32]FERC order 665's discussion of pre-filing procedures noted that it is "desirable to maximize early public involvement to promote the wide-spread dissemination of information about proposed projects and to reduce the amount of time required to issue an environmental impact statement (EIS)."

[33]Bentek, The Beast in the East: Energy Market Fundamentals Report, March 19th, 2010.

[34]Ibid.

# Chapter 7: Markets and Geopolitics

As we have seen in Chapter 3, there are substantial economic benefits to a global natural gas market. Geology, geography, and historical market and geopolitical arrangements have, however, limited the development of a global market that links supply centers to major demand centers, which would have significant energy security ramifications.

At present, trade is centered in three distinct regional gas markets — North America, Europe (including Russia and North Africa), and Asia with links to the Persian Gulf (see Figure 3.11). Each has a different market structure resulting from the degree of market maturity, the sources of supply, the dependence on imports, and other geographical and political factors. Importantly, these regional markets set natural gas prices in different ways. In general, the U.S. has gas-on-gas competition and open access to pipeline transportation, and manages risk through spot and derivatives markets. The European market relies more heavily on long-term contracts with price terms based on a mix of competing fuels, e.g., fuel oil, and pipeline access is restricted. Asia uses crude oil as a benchmark for natural gas prices and favors long-term contracts; this structure has kept LNG prices in Europe and Asia high relative to other regions. These market features, along with the availability of domestic natural gas resources and geopolitical interests, establish the boundary conditions for the development of global natural gas markets, at the same time that significant price disparities between regions create greater interest in such a market.

This regionalized and varied structure of natural gas markets stands in contrast to the global oil market, and it is instructive to understand the fundamentals of the difference between oil and natural gas markets. The physical characteristics of oil — a very high energy density at normal conditions of temperature and pressure — make it readily transportable over long distances, by a variety of means, at moderate cost. This has allowed the development over time of a global oil market, where multiple supply sources serve multiple markets at transparent spot prices, with price differences largely attributed to transportation costs and oil quality. Notwithstanding dependence on imports, the diversity and robustness of this marketplace adds significantly to security of supply for consumers and to security of markets for producers.

In comparison, natural gas markets are smaller and less mature, and the physical characteristics of natural gas constrain transportation options. Unlike oil, transportation costs — whether for pipeline gas or liquefied natural gas (LNG) — constitute a significant fraction of the total delivered cost of natural gas. Also, because of the relative immaturity of natural gas markets, compared to oil, and the very high upfront capital costs, long-term contracts have been necessary to underwrite the cost of infrastructure development and to ensure a market for the supplier.

Pipeline gas accounts for almost 80% of today's interregional gas trade (a share that is expected to decline as the LNG trade grows). Pipelines may transit many countries. The number of parties involved in a multi-national pipeline project can slow project development considerably and political instability in host or transit nations raises security of supply issues. Also, cross-border pipelines must invariably comply with multiple and dissimilar legal and regulatory regimes, further complicating pipeline construction and operations. Finally, the strong mutual interests of buyers and sellers in cross-border pipeline projects are not fully shared by transit nations, such as Ukraine for Russian supply to Western Europe.

Pipelines have a distinct economic advantage over LNG for shorter distances, but LNG gains advantage over longer distances and is a key enabler of a global gas market. LNG offers the potential for a greater diversity of suppliers and markets, both key ingredients for increased reliability and energy security. Also, LNG is generally contracted between a single buyer and seller, simplifying contract negotiations and transport routes. However, the investment required for capacity expansions of each link in the LNG supply chain is considerable; since minimizing investment risk is a fundamental driver for developing global LNG markets, longer-term contracts are favored.

*The U.S. natural gas market functions well, with infrastructure development more or less keeping pace with changing market needs.*

The geological realities of natural gas resources are similar to those of oil in terms of the degree of concentration of conventional resources, with Russia, Iran, and Qatar having the largest conventional natural gas resource base (see Chapter 2). As with oil, at issue is the extent to which major resource holders, over time, will manipulate supply and prices to advance political and/or economic objectives in ways that are detrimental to the U.S. and its allies. Consequently, the future structure of these markets and the degree of integration that may develop have both economic and security implications. Several factors could lead to greater market integration and diversity of supply:

- the competition for supply from regions that can serve multiple major markets, such as the Caspian;
- growth in LNG trade and the development of a market in which cargoes seek favorable prices, a trend that has been seen in the Atlantic basin; and
- development of major unconventional gas resources could diversify supply in strategic locations such as Europe and China, with mixed implications for market integration.

Of course, there are many unknowable factors that can impede market integration, including the geopolitical aims of current and future natural gas exporters.

## MARKET STRUCTURES

### The U.S. Market

The U.S. natural gas market is the most mature of the world's three major regional markets. Significant exploitation of natural gas began in the latter half of the 19th century centered in Appalachia, with much larger production and consumption starting in the 1920s after discoveries in the Southwest. This expansion was aided by advances in pipeline technology, eventually creating a continent-wide, integrated natural gas market.

The regulatory institutions governing the natural gas markets in the U.S. have undergone their own historical evolution. New Deal initiatives in the 1930s broke the control of the holding companies over local utilities and established the Federal Power Commission as a regulator of the interstate sale and shipment of natural gas. The Natural Gas Act of 1938 and its subsequent amendments provided Federal eminent domain authority for the construction of new interstate natural gas pipelines and natural gas storage. These policies facilitated the robust growth of a continent-wide network.

Initially, long-term contracts were the rule. There was no single benchmark price for natural gas in the U.S. This changed with the passage of the Natural Gas Policy Act of 1978, which gradually led to the removal of price controls on the interstate sale of natural gas in the U.S. Starting in 1985, ceilings were removed on the sale of new natural gas and the Federal Energy Regulatory Commission (FERC) issued a series of Orders between 1985 and 1993 that served to create an open and transparent continent-wide market in natural gas. This market-based focus was extended to natural gas storage in the Energy Policy Act of 2005.

A robust spot market has developed in the U.S. and Canada, with prices set by the forces of supply and demand. Contracts continue to play a role, albeit diminished, in the market, where price clauses typically reference the spot market. This expansion has been supported by an expanded pipeline network and associated midstream gas facilities. The U.S. natural gas market functions well, with infrastructure development more or less keeping pace with changing market needs (see Chapter 6).

At present, North America is largely self-sufficient in natural gas, and this situation is likely to continue for some time, as indicated in Chapter 3. The substantial surplus of LNG import capacity, discussed in Chapter 6, effectively provides backup capacity in the event of unanticipated supply shortfalls or high prices.

It should also be noted that the U.S. exports natural gas. LNG exports from Alaska to Japan have been in place for 40 years, but are likely to face additional competition in the Asian market, particularly as the Cook Inlet production tapers off. Part of this competition may come from Canada, which has a large shale gas resource. The Department of Energy (DOE) has approved an application to export LNG from a Gulf of Mexico (GOM) facility. The U.S. also exports natural gas by pipeline to Mexico and Canada, although with a significant net import from Canada. Especially since passage of the North American Free Trade Agreement (NAFTA), there has been increased North American energy market integration.

The large Canadian shale gas resource adds to the diversity of supply within the functioning North American market.

## U.S. Oil and Natural Gas Prices

There have been long-running discussions about the relationship between oil and natural gas prices; these have intensified as the ratio of oil to natural gas prices reached historic highs over the last year. This growing spread could have enormous implications for U.S. natural gas markets and is especially critical for gas producers, industrial gas users, and the use of natural gas as a transportation fuel. For Compressed Natural Gas (CNG) or LNG vehicles, a low natural gas price relative to oil is essential for a reasonable payback period because the vehicle capital cost is appreciably higher (see Chapter 5). In this chapter, we explore the history of these prices and price movements in the U.S. market during the preceding decades.

Oil prices have hovered around \$100/barrel (bbl) for much of the last year while the U.S. Henry Hub (HH) price has been consistently below \$5/MMBtu, for a ratio at or above 20. (We caution the reader that this ratio involves two different quantities; it is normally stated in terms of the price for a barrel of oil, about 6 MMBtu, in relation to the price for a 1 MMBtu of natural gas because these are the benchmarks in commodity markets.) A common assumption is that opportunities for substituting oil for natural gas, and vice versa, will equilibrate the prices. A simple energy equivalency argument would pin the price of a barrel of oil at about six times the natural gas price, but this simple energy-equivalence argument is unlikely to be accurate because oil and natural gas undergo different processing, distribution, and storage for different end uses. A number of "rules of thumb" have emerged. An empirical rule that is often invoked sets the crude oil/gas price ratio at 10. Others are based on the competition between natural gas and distillate fuel oil or between natural gas and residual fuel oil, using typical ratios of fuel oil and crude oil prices.

**Figure 7.1 Log Values of the Natural Gas and Oil Spot Prices, 1991–2010 (2010 dollars)**

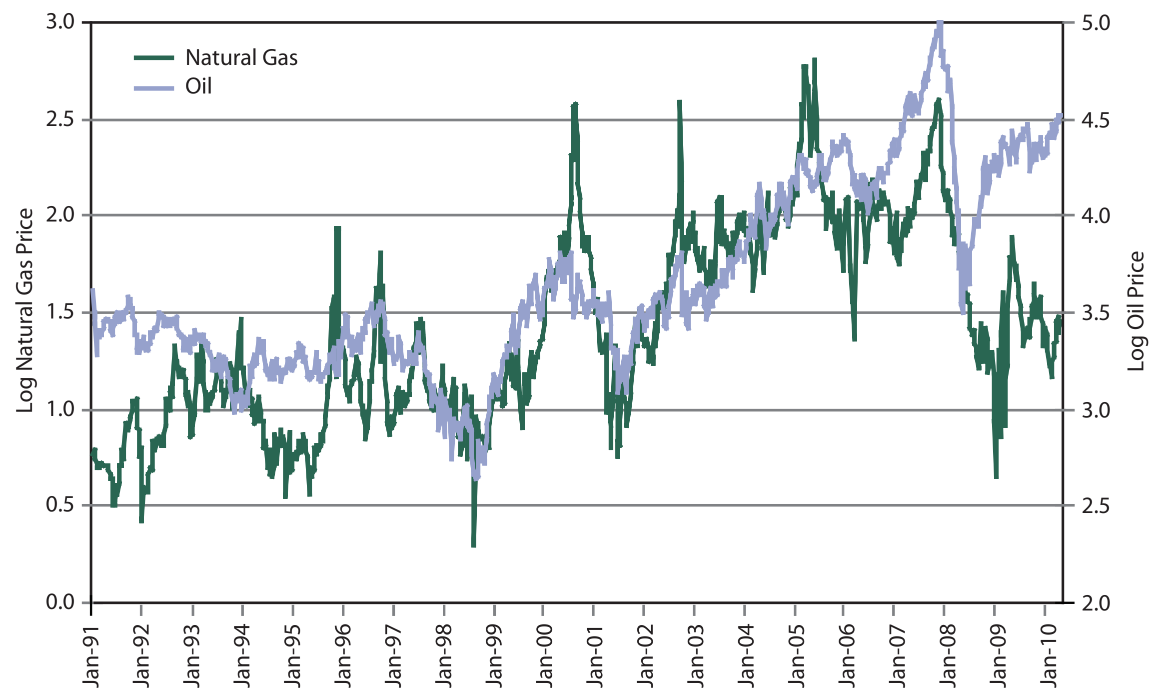



Figure 7.1 shows the (natural) logarithm of the HH natural gas price and the West Texas Intermediate (WTI) crude oil price (the logarithms are used so that the same percentage change in price appears the same irrespective of the price) over the period 1991 to 2010. It is clear in Figure 7.1 that no simple rule of thumb can fully capture the relationship between the natural gas and oil prices. The natural gas price is approximately twice as volatile as the oil price, and short-run swings in both prices are overlayed on top of whatever long-run relationship may exist. A more detailed statistical analysis by Ramberg and Parsons confirms this point even after incorporating key exogenous factors affecting the natural gas price, such as seasonality, storage levels, shut-in production, and the vagaries of weather.[1] Nevertheless, they also find that it is possible to identify a statistically significant relationship between the two price series.

Figure 7.2 shows the data of Figure 7.1 as a set of WTI and HH price pairs along with the simple rules of thumb indicated above.[2] Over this time period, the oil and natural gas prices each spanned a wide range, and the ratio of the WTI and HH prices ranged from about 5 to 20. None of the simple rules of thumb reproduce the principal trends over the full range of oil prices. However, it is interesting that, during the period 1991 to 2010, the oil/natural gas price ratio consistently exceeded 10, sometimes substantially, when the WTI price was above $80/bbl. As already noted, the ratio is close to 20 in the first half of 2011. Should these price ratios persist at high oil prices, the opportunities for opening up the transportation fuels market to natural gas would be enhanced.

## Figure 7.2 Price Benchmarks Versus Observed Prices 1991–2010

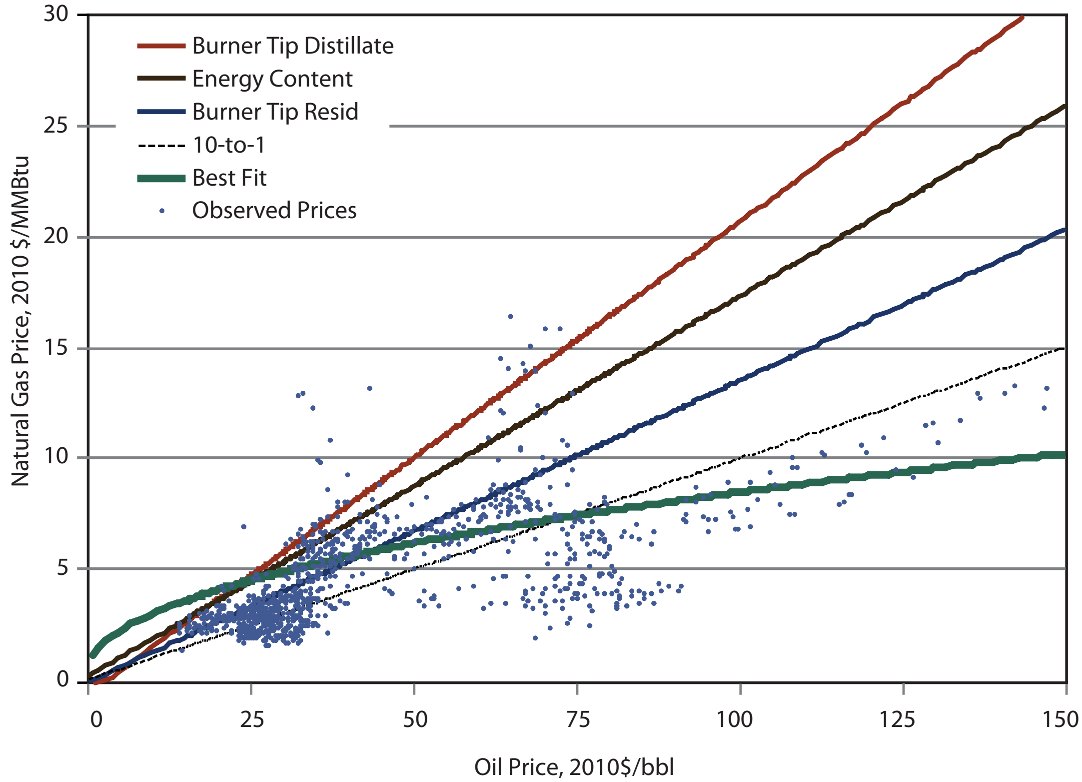



Figure 7.2 charts natural gas prices as a function of oil prices. The four straight lines show the four pricing rules-of-thumb. Using the ordering of the lines at the right of the figure, the top line is the burner-tip parity rule based on natural gas competing with distillate fuel oil, the second line is the energy-content equivalence rule, the third line is the burner-tip parity rule based on natural gas competing with residual fuel oil, and the fourth line is the 10-to-1 rule. The slightly curved line is the best-fit line calculated from a statistical analysis incorporating a number of additional variables and dynamics. The scatterplot of data points are the actual price combinations observed over the 1991 to 2010 period. All observed prices are quoted in real terms in 2010 dollars.

Using a relationship that is linear in the logarithm of prices, and accounting for a number of additional variables moving the natural gas price, Ramberg and Parsons derive a best-fit that can be approximated as:

$$\frac{P_{WTI}}{P_{HH}} = 10\sqrt{\frac{P_{WTI}}{70}}$$

with the WTI and HH prices in dollars. This relationship is also shown in Figure 7.2 (solid line, labeled "best fit" relationship) and captures, to some extent, the increasing price ratio with increasing oil price. However, their analysis also confirms that the "best fit" relationship has shifted towards higher oil/gas price ratios in recent years.[2]

*During the period 1991 to 2010, the oil/gas price ratio consistently exceeded 10, sometimes substantially, when the WTI price was above $80/barrel… Should these price ratios persist at high oil prices, the opportunities for opening up the transportation fuels market to natural gas would be enhanced.*

### European and Asian Markets

The European natural gas market developed later than that in the U.S. The initial impetus came with the discovery of the Groningen fields in the Netherlands starting in 1959. In the early 1960s, Algeria began LNG shipments to the U.K., then to France. Small quantities of natural gas from the Soviet Union flowed into the other countries of Europe beginning with Austria in 1968.

The current structure of Europe's natural gas markets is shaped by the 1973 Organization of the Petroleum Exporting Countries (OPEC) oil embargo. The European reaction was to explicitly tie the delivered price of natural gas to the price of crude oil or crude products. This limits the development of a deep and liquid spot natural gas market in Europe.

Currently, almost half the natural gas for Organization for Economic Cooperation and Development (OECD) Europe is imported, mostly by pipeline from Russia and North Africa, sometimes traversing other countries. LNG also supplies parts of Europe and is especially important to Spain and Portugal, which are on the far end of the Russian pipeline system.

The long supply chains into Europe, the prevalence of pipeline gas, and the relative inflexibility of the markets create much more significant security of supply concerns than are experienced in North America. Diversification of supply is a high priority. However, even though the U.S. is not significantly dependent on imports, American security interests can be strongly affected by the energy supply concerns of its allies.

There have been moves in the EU to liberalize gas markets, starting with the U.K. in 1986. As part of a larger energy market liberalization effort, the EU in 1998 sought to create common rules for an internal natural gas market. The result has been the development of a small spot market on the European continent. Ultimate success will depend upon the future course of the EU's regulatory reform. Progress is slow.

Industrialized Asia led the way in setting LNG prices through oil-indexed long-term contracts and remains bound to this market structure. This does not appear likely to change in the near term. With limited indigenous conventional natural gas resources, industrialized Asia and the emerging economies in that region are almost totally dependent on imported LNG from Southeast Asia, Australia, and the Middle East. This dependence places a high premium on security of supply, which is reflected in the region's dependence on long-term, relatively high-priced contracts indexed to oil.

The indexation of natural gas contract prices to the oil price was a necessary innovation to enable long lead-time contracts to partially accommodate fluctuating energy prices. But oil is an imperfect index for natural gas, as seen in our discussion of U.S. prices. Since the spot market oil and natural gas price relationship does not match any simple formula, an oil-indexed contract price cannot mimic very well the spot natural gas price; oil indexed prices are out of sync with the value of marginal deliveries of natural gas, sometimes being too high and other times too low. Therefore, they cannot give the right signals for consumption of natural gas, inhibiting efficient use of the resource. In order for both buyers and sellers to capture the full value of natural gas resources, it is essential for long-term contracts to reflect the specific supply and demand conditions of natural gas, meaning a liquid market in gas spot deliveries. Absent this, buyers and sellers have not been able to do better than index contracts to the liquid oil price. Encouragement of the expansion of a liquid market in spot natural gas deliveries in Asia is in the interest of buyers and sellers and other parties in the value chain. As the use of natural gas grows throughout industrialized Asia and Europe, the opportunity is ripe to realize the establishment of a spot market. This would make it possible to switch long-term contracts from a price linked to spot oil markets to a price linked to spot natural gas markets. In turn, this will create the opportunity for the expanded use of natural gas and improve the possibility for international linkage. Nevertheless, the path to a spot market is likely to be complex and slow, and long-term contracts operating side by side with the spot market will be necessitated by the capital requirements of very long pipelines and LNG infrastructure.

Finally, we note that domestic markets in some major supplier countries, such as Russia, operate with very large subsidies. This leads to inefficient use that impacts volumes of natural gas available for export.

*Long-term contracts operating side by side with the spot market will be necessitated by the capital requirements of very long pipelines and LNG infrastructure.*

### IMPLICATIONS OF MARKET INTEGRATION

Extrapolating from the lessons learned from the North American market, an interconnected delivery system combined with price competition are essential features of a "liquid" market. This system would include a major expansion of LNG trade with a significant fraction of the cargoes arbitraged on a spot market, similar to today's oil markets.

As described in Chapter 3, the Emissions Prediction and Policy Analysis (EPPA) model was used to investigate the consequences of global natural gas prices differentiated only by transportation costs (which are appreciable for long distances between buyer and seller). We emphasize that this is not a prediction that such a market will emerge, but rather an exploration of the implications of global market integration. For the U.S., with the median expectations for both North American and global gas resources, the U.S. becomes a substantial net importer of gas in future decades in an integrated market and long-term domestic prices are lower than in the regionalized market structure. Also, greater diversity of supply is seen for all the major markets in this scenario. Clearly other scenarios could result from changes in resource estimates or from geopolitical realities.

*Extrapolating from the lessons learned from the North American market, an interconnected delivery system combined with price competition are essential features of a "liquid" market.*

In addition, a functioning integrated market can help overcome disruptions, whether political in origin or caused by natural disasters. An example of this was seen in the U.S. oil markets, which recovered quickly following the 2005 hurricanes in no small part because of international market adjustments.

Overall, a "liquid" global natural gas market would be beneficial to U.S. and global economic interests and, at the same time, it would advance security interests through diversity of supply and resilience to disruption. These factors moderate security concerns about import dependence.

### DIVERSITY OF SUPPLY

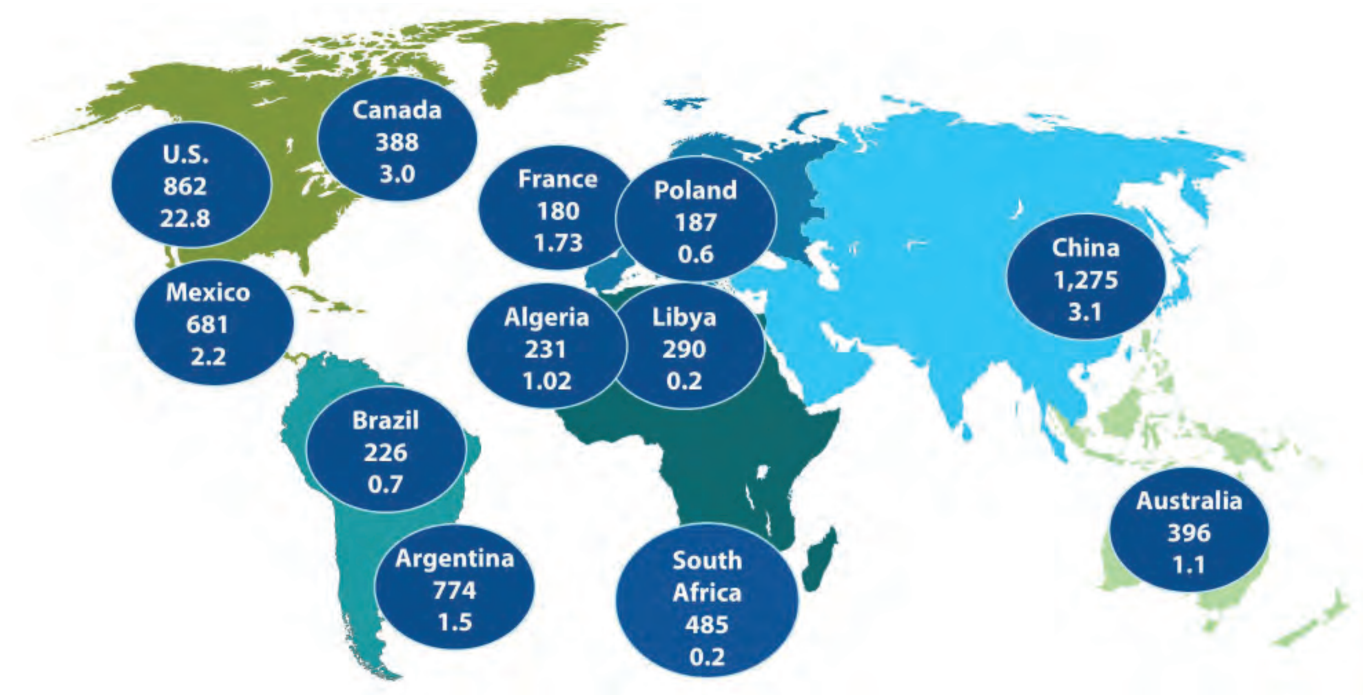
As already noted, the distribution of conventional natural gas resources is highly concentrated, with Russia, Iran, and Qatar being the largest resource holders. Indeed, the global market scenario of Chapter 3, referenced above with regard to U.S. import possibilities, shows Russia and the Middle East becoming major suppliers to all three of the major regional natural gas markets — the U.S., Europe, and industrialized and emerging Asia. The recent experience of Europe (curtailment of Russian natural gas) and the uncertain political future in the Middle East are a cause of concern, especially in Europe and Asia because of their large demand and limited or declining production.

As has already happened in the U.S., unconventional resources could change the picture dramatically. The Energy Information Administration (EIA) recently released "World Shale Gas Resources: An Initial Assessment".[3] This report, prepared by Advanced Resources International (ARI), presents estimates for potential shale gas development in 48 basins in 32 countries outside the U.S. It does not include regions with large conventional resources, such as Russia and the Middle East, since these seem unlikely to develop the shale resource in the near future. Even with this restriction, the estimate is for 5,760 Trillion cubic feet (Tcf), which is a substantial fraction of the approximately 16,000 Tcf mean estimate of global resources discussed in Chapter 2. None of these shale resources was included in the global estimate or in the trade models of Chapter 3. ARI acknowledges that the estimates may have considerable uncertainty at this time, and will be refined over time as the shale resources are investigated by an increasing number of industry players.

*The scale of the global shale gas resource is a potential game-changer…the trade flows in a global market could be affected substantially…and the leverage of Major Resource Holders (MRHs) to follow politically motivated strategies would presumably be diminished.*

The distribution of these shale resources is also interesting. Figure 7.3 shows some of the results[3] along with the current annual natural gas use in those countries. Pertinent to the discussion above, France and Poland are each estimated to have around 180 Tcf, and China over 1,200 Tcf.

**Figure 7.3 Global Shale Opportunities: Technically Recoverable Shale Reserves and 2009 Consumption (Tcf)**




Source: : EIA/ARI, 2011

These resources dwarf annual use and therefore present the possibility of exports that significantly affect import requirements for their regional natural gas markets. How this plays out remains uncertain; for example, while Poland intends to pursue production aggressively, France has declared a moratorium because of concerns about environmental impact. Nevertheless, the trade flows in a global market could be affected substantially if the global shale gas resource is developed at scale over the next decade or so, and the leverage of Major Resource Holders (MRHs) to follow politically motivated strategies would presumably be diminished.

Conventional natural gas finds, even if not on the scale of the apparent shale resource, can also impact diversity and security of supply when they occur in strategic locations. A recent example (2009 and 2010) is the large offshore finds in the eastern Mediterranean Levantine basin. The expectation is for more than 25 Tcf of resource in the Israeli economic zone. Inevitably, there will be issues to be resolved involving the maritime borders of Israel, Lebanon, Gaza, and Cyprus. Nevertheless, it appears that the security of supply for Israel, which currently uses about 0.2 Tcf of natural gas per year, has been transformed by the offshore natural gas finds. In particular, it offers the possibility of greatly reduced oil dependence through direct or indirect use in transportation.

## NATURAL GAS SECURITY CONCERNS AND RESPONSES

Energy supply generates security concerns when an economy is exposed to sudden disruptions that cannot be addressed by substitution of alternative primary energy sources. It should be noted that any source can be replaced with sufficient time and investment. For example, security concerns led France to make a strategic decision to base its electricity supply on nuclear power. Restricted access to oil led World War II-era Germany and Apartheid-era South Africa to large coal conversion to liquid fuel programs. For natural gas, the end use with the most difficulty for adjustment to a sudden disruption is space heating. This was seen in January 2009 when Russian natural gas to Europe was cut off because of a dispute with Ukraine, a key pipeline transit country from Russia to Europe. Although the U.S. is not at risk of natural gas supply disruptions because of the large North American resource and production infrastructure, the vulnerability of key allies is itself a security concern. Furthermore, the opportunity to substitute natural gas for oil as a transportation fuel feedstock improves resilience to "oil shocks."

Transparent markets with diverse supply, whether global in reach or within large regions that encompass both major suppliers and large demand centers, do much to alleviate security risks. Nevertheless, the anticipated growth in gas use, combined with the geological realities of conventional gas resources, inevitably will produce continuing concerns, such as:

1. **Natural gas dependence could constrain U.S. foreign policy options.** U.S. freedom of action in foreign policy is tied to global energy supply. Iran, for example, presents many security challenges in the Middle East and is in confrontation with the West over a developing nuclear weapons capability. However its oil exports and its potential for natural gas exports set up conflicting objectives for the U.S. and its allies: altering Iran's behavior, yet not risking supply interruptions of the oil and (eventually) natural gas markets. Such situations threaten allied cohesion in foreign policy.

   Specifically, the U.S., with its unique international security responsibilities, can be constrained in pursuing collective action if its allies are limited by energy security vulnerabilities.[4] The natural gas cutoff to Europe demonstrated Russia's market power in a situation where key allies have inadequate alternative supplies and insufficient short-term substitution possibilities in a key sector. Russia has argued that the Ukraine dispute was commercial, that Ukraine should not have blocked transshipments, and that it is a reliable supplier. However, the fact that they were selectively moving towards market prices in some Former Soviet Union states and not others suggested political motivations for the disruption. In any event, security implies removing or minimizing vulnerabilities, so U.S. support and encouragement of shale gas development, alternative pipeline supplies (e.g., from the Caspian region) and transparent LNGs markets with a robust LNG infrastructure should be viewed as favoring U.S. security interests.

*A global "liquid" natural gas market is beneficial to U.S. and global economic interests and, at the same time, advances security interests through diversity of supply and resilience to disruption.*

2. **New market players could introduce impediments to the development of transparent markets.** The new large consuming economies, such as China and India, are increasingly seeking bilateral arrangements that include non-market concessions. Such arrangements have the potential to influence long-term political alignments, move away from open, transparent natural gas markets, and work against the interests of consuming nations as a whole. Major natural gas producers have shown some interest in forming a cartel to control supply, but this movement is not yet very advanced.[5] Global shale gas developments would make such a cartel very difficult to implement effectively.

3. **Competition for control of natural gas pipelines and pipeline routes is intense in key regions.** Control of pipeline routes gives natural gas suppliers tremendous leverage over consuming nations, and competition for these routes is often a "high stakes game." The landlocked Caspian region, which possesses large oil and gas resources, provides an important example of the geopolitical complexity that can develop. Decades ago, the Caspian was surrounded by only the USSR and Iran, and the legacy natural gas pipeline infrastructure is entirely through Russia. The Russia-Ukraine-Europe natural gas delivery cutoff of 2009 spurred Europe to further its intentions to explore pipeline routes out of the Caspian Sea region to Europe while avoiding Russia. This mirrors the earlier construction of the Baku-Tbilisi-Ceyhan (BTC) oil pipeline that took an East-West route from Azerbaijan to Georgia to Turkey, but the gas pipeline is more complicated precisely because of the physical characteristics of oil and natural gas and the resulting transportation options. The BTC oil pipeline can use ships to cross the Caspian for supply from Kazakhstan and ships to export the oil from Turkey. On the other hand, the proposed Nabucco pipeline from Baku to Austria is thousands of kilometers long and crosses Romania, Bulgaria, and Hungary just from Turkey to the Austrian hub. Furthermore, supply from the Eastern side of the Caspian, particularly Turkmenistan, is crucial for supplying sufficient natural gas volumes, but a subsea pipeline to Baku faces complications because of unresolved seabed jurisdictional disputes. Yet another complication is competition for Turkmen natural gas from China, which has already begun supply through a very long pipeline to Shanghai. Not surprisingly, the competition and competing political pressures on the governments in Central Asia and the Caspian region over pipelines out of the region is intense. It is unclear how this will be resolved.

While the Caspian presents a particularly complex situation, long pipelines crossing multiple countries inherently raise trans-shipment concerns. Another example is the proposed Iran-Pakistan-India pipeline. For a summary, see "Natural Gas and Geopolitics: From 1970 to 2040".[6]

4. **Longer supply chains increase the vulnerability of the natural gas infrastructure.** As supply chains multiply and lengthen, these infrastructures have become increasingly vulnerable to both malevolent attacks and natural disasters. Pipelines, processing facilities, LNG terminals, and tankers are "soft targets," i.e., easy to locate and destroy, usually undefended, and vulnerable to attacks, including cyber attacks.

As the use and trade of natural gas grow over the coming decades, with an uncertain global market structure, U.S. policy makers must be well informed and manage the interrelationship between natural gas markets, both domestic and international, and security in order to limit adverse effects on U.S. and allied foreign policy.

## RECOMMENDATIONS

1. **The U.S. should sustain North American energy market integration and support development of a global "liquid" natural gas market with diversity of supply. A corollary is that the U.S. should not erect barriers to natural gas imports or exports.**

   Robust global LNG trade and progress toward spot pricing of cargoes, especially in Asia, are necessary for establishment of a global natural gas market.

2. **A Federal multi-agency coordinating body should be established to better integrate domestic and international implications of natural gas market developments with foreign and security policy.**

   Numerous agencies (Energy, State, Treasury, Defense, Commerce, etc.) have a major stake in this integration, so the Executive Office of the President must exercise the necessary convening power and leadership. To be successful, strong energy policy support for the coordinating group must be established in the DOE. This is in accord with the recommendation for a Quadrennial Energy Review issued by the President's Council of Advisors on Science and Technology.[7]

*A federal multi-agency coordinating body should be established to better integrate domestic and international implications of natural gas market developments with foreign and security policy.*

3. **The International Energy Agency (IEA) should be supported in its efforts to place greater emphasis on natural gas and security concerns.**

   To do so meaningfully, it must bring the large emerging natural gas-consuming economies (such as China, India, Brazil) into the IEA process as integral participants. The process should promote open and transparent energy markets, including the natural gas market.

   A global natural gas market may lead, as in the U.S., to lower natural gas prices relative to oil. If this in turn stimulates more substitution of natural gas for oil in the transportation fuels market, IEA's core mission of advancing energy security will be advanced.

4. **The U.S. should continue to provide diplomatic and security support for the siting, construction, and operation of global natural gas pipelines and LNG facilities that promote its strategic interests in diversity and security of supply and global gas market development.**

5. **The U.S. government, in concert with the private sector, should seek to share experience in the characterization and development of global unconventional natural gas resources in strategic locations. This includes strengthening the Global Shale Gas Initiative (GSGI).**

   Global shale gas resources at the several thousand Tcf scale have the potential to be game-changers with regard to the market and security issues discussed in this chapter. The U.S. has a strong interest in seeing this development and, to date, has been by far the leader in exploiting unconventional natural gas resources. The GSGI is led by the Department of State, with support from the Departments of Interior, Energy, and Commerce and from the EPA. It provides assistance as requested on resource assessments; production and investment potential; and business and regulatory issues. China, India, Jordan, and Poland are working with the GSGI.

   The experience of states in regulating environmental performance of shale gas production should also be brought to bear through the GSGI.

6. **The U.S. should take the lead in international cooperation to reduce the vulnerability of natural gas infrastructure; help set security standards for facilities and operations; and provide technical assistance for sharing threat information, joint planning, and exercises for responding to incidents.**

## NOTES

[1]David J. Ramberg and John E. Parsons, MIT Center for Energy and Environmental Policy Research report 10-017, November 2010.

[2]ibid.

[3]World Shale Gas Resources: An Initial Assessment, prepared by ARI for the U.S. EIA, April 2011, www.eia.gov/analysis/studies/worldshalegas.

[4]National Security Consequences of U.S. Oil Dependency; J. Deutch and J. Schlesinger, chairs, D. Victor, project director; Council of Foreign Relations Independent Task Force Report No. 58 (2006).

[5]What is the Gas Exporting Country Forum (GECF) and what is its objective?, EIA 2009; http://www.eia.doe.gov/oiaf/ieo/cecf.html.

[6]Natural Gas and Geopolitics: From 1970 to 2040, D. Victor, A. Jaffe, and M. Hayes, editors, Cambridge University Press, 2006.

[7]Report to the President on Accelerating the Pace of Change in Energy Technologies through an Integrated Federal Energy Policy, President's Council of Advisors in Science and Technology, November 2010, www.whitehouse.gov/ostp/pcast.

# Chapter 8: Analysis, Research, Development, and Demonstration

Natural gas is well positioned, with current technology, to play an increasingly important role in serving society's clean energy needs over the next decades, assuming a policy "level playing field." As seen in the analysis of Chapter 3, this is especially so in a carbon-constrained world, wherein the pathway to significant carbon dioxide ($CO_2$) emissions reductions has three major components:

- throughout the analysis period, significant *demand reduction* relative to business-as-usual, including reductions arising from more efficient buildings, industrial processes, and transportation technologies;
- *natural gas as an extended "bridge"* to a very low carbon future, principally by displacing the more carbon-intensive fossil fuels — coal and oil;
- *in the longer term, "zero-carbon" technologies* as the dominant energy supply, which may include fossil fuel combustion with $CO_2$ capture and storage (CCS).

Continuing research, development, and demonstration (RD&D) will play an important role in determining the interplay of these components over time, especially as RD&D affects the relative costs of various technologies and fuels. While such cost reduction requirements are particularly acute for the zero-carbon technologies, RD&D that lowers cost and minimizes environmental impact is important for all three components. Indeed such technological progress can facilitate policy implementation that accelerates $CO_2$ emissions reduction, just as policy and regulation can stimulate technology development.

In addition to prudence with regard to greenhouse gas (GHG) emissions, another important energy policy driver is reduced oil dependence. The analysis of Chapter 5 presented multiple pathways for natural gas substitution for oil in the transportation sector. Once again, the research challenges are to lower costs and increase flexibility of use.

**FINDING**

**There are numerous RD&D opportunities to address key objectives for natural gas supply, delivery and use:**

- **improve the long-term economics of resource development as an important contributor to the public good;**
- **reduce the environmental footprint of natural gas production, delivery, and use;**
- **expand current use and create alternative applications for public policy purposes, such as emissions reductions and diminished oil dependence;**
- **improve safety and operation of natural gas infrastructure;**
- **improve the efficiency of natural gas conversion and end use so as to use the resource most effectively.**

The fact that natural gas serves multiple sectors in competition with other primary fuels implies that many end-use efficiency RD&D programs will not be specific to natural gas (e.g., technology development for improving overall building energy efficiency). Similarly, there are many common elements of the technology base both for oil and gas exploration and production, such as advanced drilling technologies (e.g., nanoparticle drilling fluids) and for $CO_2$ sequestration following fossil fuel combustion (e.g., the science of $CO_2$ sequestration and monitoring, novel capture technologies, and hydrogen-rich operation of combustion turbines). Robust RD&D programs in all of these areas are very important for the future of natural gas and should be supported by public and private funding, but *our discussion in this chapter will be confined to areas that are uniquely tailored to production and use of the natural gas resource and that promise to have significant impact*.

It is worth reiterating that, while we focus on natural gas-specific technologies, the overall publicly funded energy RD&D program should have a strong portfolio dedicated to the first and third components identified above: demand reduction and zero emissions technologies. Notwithstanding the overall desirability of a level playing field, and in anticipation of a carbon emissions charge, support should be provided through RD&D and targeted subsidies of limited duration, for very low-emission technologies that have the prospect of complementing and competing with natural gas in the longer term. This would include efficiency, renewables, $CO_2$ sequestration for both coal and natural gas generation, and nuclear power.

## NATURAL GAS RESEARCH NEEDS AND OPPORTUNITIES

Relative to the role of natural gas in the energy sector, the Department of Energy (DOE), the lead government funder of energy RD&D, has historically had very small programs dedicated to natural gas exploration, production, transportation, and use. This is evident in Table 8.1, which shows Congressionally appropriated and Administration-requested amounts in recent years. In the early years of the DOE, in response to the oil shocks of the 1970s, the agency supported research and characterization work for unconventional natural gas reservoirs, and this provided an important foundation for subsequent RD&D and development of the unconventional natural gas industry (a point to be discussed later in the chapter). However, the DOE focus on natural gas RD&D was not sustained for a variety of reasons, including a fairly robust public-private partnership (the Gas Research Institute (GRI)) that was dedicated to natural gas RD&D across the value chain. The Royalty Trust Fund (RTF) indicated in Table 8.1 is an example of a more recent public-private partnership dedicated specifically to exploration and production, with public funding legislatively mandated as a very small fraction of Federal royalties on oil and gas production. Administration proposals to eliminate even this funding, made by both the previous and current Administrations, highlight the lack of agreement on the need for and role of publicly funded natural gas RD&D.

Our perspective is rooted in the importance to society of wise use of the major unconventional natural gas resource that has been fully appreciated only recently. This resource is important both for addressing GHG emission challenges and for energy security, and the public has an interest in its effective and responsible production and its efficient use. Clearly, the increasingly prominent role of natural gas in the energy mix creates an impetus for increased private sector RD&D, when the benefits of such activities can be readily appropriated. This is happening to some degree for the upstream as the major oil and oil service companies move more strongly into unconventional resources. Nevertheless, there will be a need for public and public-private funding of research with longer and/or more uncertain payback periods than will attract private funding. In addition, there are important research needs for natural gas transportation and end use in addition to production. Priority RD&D areas specific to natural gas follow.

**Table 8.1 DOE Gas Technologies RD&D Program Funding ($ Million)**

| | FY08 | FY09 | FY10 | FY11 (Req) | FY12 (Req) |
|---|---|---|---|---|---|
| Gas Hydrate Technologies | 14.9 | 14.6 | 15.0 | 17.5[1] | 10.0 |
| Effective Environmental Protection | 5.0 | 4.9 | 2.8 | 0.0 | 0.0 |
| Total Natural Gas Technologies | 19.8 | 19.4 | 17.8 | 0.0 | 0.0 |
| Royalty Trust Fund | 50.0 | 50.0 | 50.0 | 0.0 | 0.0 |
| **Total Government Spending** | **69.8** | **69.4** | **67.8** | **17.5** | **10.0** |

Source: FY 2009 – 2012 DOE Budget Request to Congress.[2]

### *Improving the Economics of Resource Development*

**Analysis and Simulation of Gas Shale Reservoirs.** Our discussion of supply in Chapter 2 demonstrates the importance of shale gas to the overall supply curves, but also noted the potential for substantially higher resource production. DOE R&D funding should be aimed at the basic science that governs shale formations. Such a program could help develop a better understanding of the physics that underlies fluid flow and storage in gas shales, facilitate the development of more accurate reservoir models and simulation tools, and develop imaging tools and models for characterizing the geologic, geochemical, and geophysical shale rock properties. The models should be able to predict the short-term and long-term behavior of induced and natural fractures in an integrated fashion. Practical 3-D models can improve reservoir management. Better resource characterization will enable assessment of resource play potential and well performance based on petrophysical measurements.

Improved microseismic formation mapping will advance optimization of real-time fracture treatments. At the macroscopic scale, new seismic techniques should be developed to identify "sweet spots" and natural fracture orientation. Publicly funded research in these areas will promote transparency into the effective use of the critical shale resource.

**Methane Hydrates.** The Chapter 2 discussion also indicates the potential for major methane resources from economic hydrates production. More basic research issues need to be resolved for methane hydrates than for other natural gas sources. RD&D might usefully focus on: the systematic remote detection of highly concentrated deposits; long-term production tests, particularly in permafrost-associated hydrates; and geo-hazard modeling to determine the impact of extracting free natural gas on the stability of associated hydrate-bearing sediments.

The longest production test to produce natural gas from forced dissociation of methane hydrate deposits had only a six-day duration due to the nature of the experiment, financial concerns, and other issues. The technology and expertise to conduct a long-term production test exist today. Financial and logistical barriers have been the major impediments to completing such a test in permafrost-associated hydrates. Determining the degree of safety and environmental risk associated with production from natural gas hydrates will require that appropriate data be collected during and after long-term production tests that are conducted over the next few years. Many of the safety and environmental issues will have to be addressed by modeling that takes into account a range of potential risks, including blowouts; co-production of $CO_2$, water and gasses;

borehole, formation and/or seafloor destabilization; and warming and potential thawing of permafrost.

Methane hydrates are a good candidate, sometime in the future, for another public-private success story of the type illustrated in Box 8.1 for coalbed methane (CBM), i.e., a combination of government funding for resource characterization, public-private partnership for technology transfer, and synergistic, time-limited financial incentives to advance commercial deployment. As the majors move into today's unconventional resources and apply their research capacity, methane hydrates could be thought of as "tomorrow's unconventional resource."

### *Reducing the Environmental Footprint of Natural Gas Production, Delivery, and Use*

**Water.** As discussed in Chapter 2, a comprehensive program is needed to address issues of water use and backflow and produced water in unconventional gas production. Such a program could lead to: improved treatment, handling, re-use, and disposal of fluids; more sustainable and beneficial use of produced water; and more effective stimulation techniques that require less water and other fluids to be injected into the subsurface. Nearly complete recycle of flowback frac water is an important goal. Some of the key water treatment needs include removal of polymers, control of suspended solids, and scale control. Basic research on novel approaches is appropriate for public support.

**Natural Gas Combined Cycle with CCS.** Chapter 4 highlighted the importance of natural gas in an electricity system with large amounts of variable and intermittent sources. If $CO_2$ emission constraints are severe enough to require the capture of $CO_2$ from natural gas as well as coal plants, it will be important to understand the cycling characteristics and possibilities for natural gas power plants with CCS. This need will be ameliorated if inexpensive large-scale storage solutions are developed, but a research program to understand cycling capabilities at different time scales for natural gas generation would be prudent.

**Fugitive Emissions.** Methane emissions in natural gas production, transportation, and use are not well understood. Research is needed for developing technologies and methodologies for reliably detecting and measuring such emissions. This may have significant monetary consequences in a world where $CO_2$ emissions are priced. Furthermore, the economic value of the methane implies that capture of the natural gas emissions for beneficial use merits development of improved technologies and methods.

The DOE and EPA should co-lead a new effort to review, and update as appropriate, the methane and other GHG emission factors associated with fossil fuel production, transportation, storage, distribution, and end use. These results are important for overall energy policy, as discussed in Chapter 1.

### Box 8.1 Unconventional Gas: Public/Private Partnerships and Tax Incentives

The interplay of early DOE funding, industry-matched GRI applied RD&D, and synergistic policy incentives had a material impact on U.S. unconventional natural gas development. This is illustrated in Figures 8.1 and 8.2 for CBM and shale, respectively.[3] The DOE funding was focused on reservoir characterization and basic science. GRI implemented industry-led technology roadmaps leading to demonstration. This overlapped with a time-limited tax credit put in place for wells drilled from 1980 to 1992, with their production eligible for the credit through 2002. The results of this multi-pronged approach to public-private RD&D and deployment are particularly striking for CBM. For shale, the program is credited with laying a foundation by developing new logging techniques, reservoir models and stimulation technologies. See Appendix 8.A.

**Figure 8.1 CBM RD&D Spending and Supporting Policy Mechanisms**

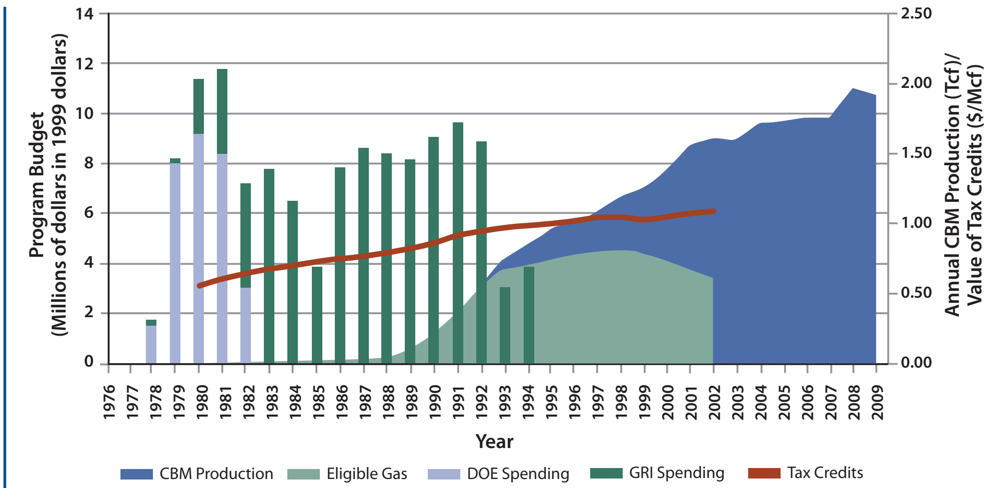
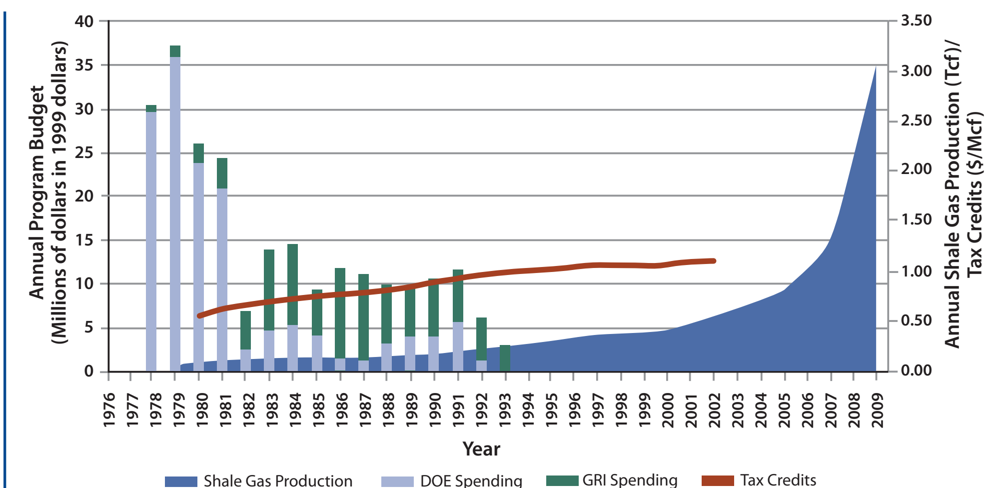



**Figure 8.2 Shale Gas RD&D Spending and Supporting Policy Mechanisms**



### *Expanding Current Use and Creating Alternate Applications for Natural Gas*

**Power Generation.** As seen in Chapter 3, natural gas use in the power sector is expected to increase substantially. Growth will be especially important under $CO_2$ emissions constraints, since natural gas substitution for coal is, along with demand reduction, the least costly response in the near-to-intermediate term. We also saw in Chapter 4 that natural gas capacity is likely to increase substantially in response to a greater deployment of wind and solar, and transmission constraints and natural gas infrastructure are both central considerations for such a development (Chapter 6). Advanced analysis and simulation tools are needed for the converged electricity and gas sectors. Such tools will be invaluable for informing technically grounded energy policies and regulations. The model/simulation tools need to incorporate several features, including:

- development of better hybrid models for integrating power sector top-down and bottom-up approaches;
- integrated understanding of power system operation and natural gas distribution requirements with large penetration of intermittent sources, distributed generation, and smart grids;
- both near-term and long-term planning tools for electricity and gas capacity planning and infrastructure development.

**Mobility.** As noted in Chapter 5, natural gas currently plays a very small role in transportation. In the U.S., it is used almost exclusively for fleets with high mileage and small geographical area driving requirements. However, the strong desire to reduce oil dependence, together with today's historically large spread between oil and natural gas prices, has led to an examination of natural gas as a material alternative transportation fuel. This can be accomplished either through direct use in combustion engines or through conversion to a liquid fuel.

For light-duty vehicles, extensive simulations of the safety and environmental performance of vehicles retrofit for CNG operation should be carried out with a view to streamlining regulations and lowering cost, to bring U.S. conditions more in line with the certified retrofit costs elsewhere.

There are multiple pathways to natural gas-derived liquid transportation fuels (methanol, ethanol, mixed alcohols, Dimethyl Ether (DME), diesel, gasoline, etc). Various fuels and fuel combinations can be used in appropriately modified internal combustion engines, including optimization for increasing efficiency by use of alcohol fuels and DME. Different fuels will have different fueling infrastructure requirements. The DOE should support a comprehensive end-to-end analysis, supported by engineering data, of the multiple pathways. The analysis would include an assessment of costs; vehicle requirements; environment, health, and safety effects; and technology development needs. This information will be important for guiding energy policy and the introduction of oil alternatives.

### *Improving Conversion Processes*

Industry has often been at the forefront of energy-efficiency improvements because of the direct impact on the bottom line, but significant additional opportunities lie at the nexus of energy efficiency, environmental quality, and economic competitiveness. Some process improvements may require substantial changes in manufacturing, such as novel membranes for separations, more selective catalysts-by-design for synthesis, or improved systems integration for reduced process heating requirements. In the chemicals industry, the promise of biomass feedstocks and new bioprocessing technologies is attracting considerable interest and needs further RD&D. Yet another opportunity would be development of new process technologies for low-temperature separation methods. Such developments can substantially reduce natural gas requirements and improve industrial competitiveness.

The potential for significant reductions in the use of natural gas for industrial process heating lies in a shift to new manufacturing process technologies that require less process heat or utilize new, less energy-intensive materials (Chapter 5).

The DOE should support pre-competitive research in these areas and also use its convening power to bring together energy-intensive industry sectors to identify opportunities for lowering energy needs, emissions, and costs. Roadmaps for future energy-efficiency technology improvements would be developed through this public-private collaboration. This is essentially the role played in the past by the Industries of the Future Program, and something like it should be re-created. Crosscutting technologies applicable across a broad spectrum of manufacturing industries (such as materials for extreme environments and separation technologies) would also be identified and should be included in a new DOE program.

### *Improving Safety and Operations of Natural Gas Infrastructure*

Pipeline safety, discussed in Chapter 6, is an increasingly critical issue because of the age of much of the natural gas transmission and distribution system. There is a strong public interest in this area, but the Federal program is small. Public-private partnership is appropriate for:

- improving monitoring and assessment of system integrity;
- enhancing system reliability and resilience;
- reducing the incidence and cost of subsurface damage;
- lowering cost of construction, maintenance, and repair;
- improving data quality;
- minimizing the environmental footprint.

In addition, the DOE should support novel concepts focusing on in-line inspections, corrosion prevention and protection, and anticipatory maintenance.

Modeling and simulation tools should be developed in the public domain for analysis of the growing interdependency of the natural gas and power generation infrastructures. These are needed to support analysis of the system impacts of increased use of natural gas for power generation and associated infrastructure stresses and vulnerabilities, particularly with respect to changes in storage and deliverability requirements.

### *Improving the Efficiency of Natural Gas Use*

We saw in Chapter 5 that, in addition to power generation and industrial use, the other major use of natural gas is for space conditioning and appliances in residential and commercial buildings. Lower-cost, gas-fired, instantaneous hot water heaters are an example of an appliance improvement that can significantly reduce natural gas consumption. Similarly, lower-cost, high-efficiency heat pumps for appropriate climates can economize on natural gas used for space heating. Advances in these and other building energy technologies are a good target for public-private partnerships.

Combined heat and power (CHP) was seen in Chapter 5 to offer significant system efficiency, emissions and economic benefits, especially for larger installations (Megawatt scale). This should be encouraged. However, micro-CHP (kilowatt scale) will need a substantial breakthrough to become economic. Micro-CHP technologies with low heat-to-power ratios will yield greater benefits for many regions, and this suggests sustained research into kW-scale, high-temperature, natural gas fuel cells. Basic research into new nano-structured materials will be central to such programs.

## FUNDING AND MANAGEMENT OF NATURAL GAS RD&D

Given the importance of natural gas in a carbon-constrained world, and the opportunities indicated above for improved utilization of the resource, an increase is in order in the level of public and public-private RD&D funding indicated in Table 8.1. However, the budgetary pressures facing the Administration and Congress dim the prospects for additional appropriations in the next several years. To discuss an alternate path forward, it is important to understand the history that led to the current low level of research support. A more detailed description of natural gas RD&D funding is given in Appendix 8.A.

The DOE natural gas research funding history is summarized in Figure 8.3. Between 1978 and 2010, the total expenditure was just over $1 billion. Major elements have included:

- assessing and characterizing unconventional natural gas resources (especially shale) in the early years of DOE operations;
- small but consistent support for research on environmental protection;
- an exploration and production program focusing on advanced drilling, completion and stimulation;
- development of high-temperature, high-efficiency, low NOx gas turbines in collaboration with industry during the 1990s, with nearly $300 million of DOE support (see Appendix 8.B);
- methane hydrates research during the last decade.

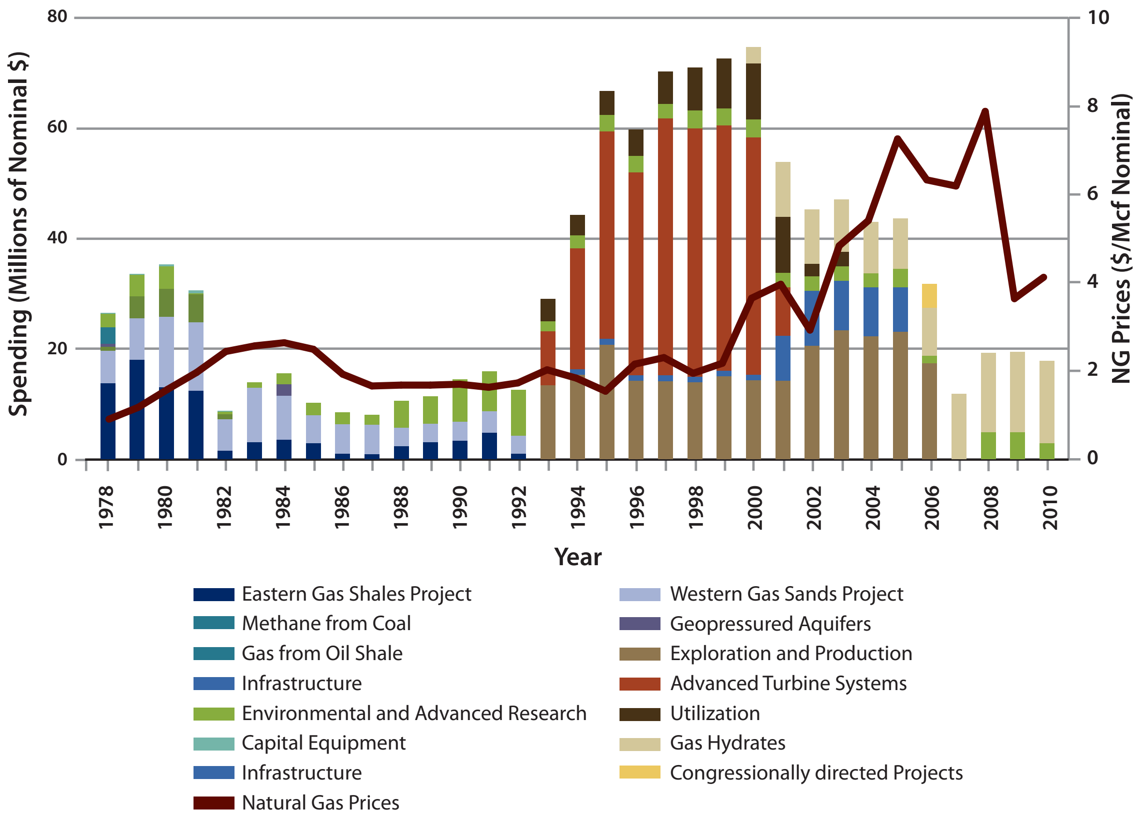
Apart from the funding increase to support the cost-shared advanced turbine development, the program has averaged about $24 million/year.

This low funding level must be viewed in the context of parallel public-private approaches to natural gas research funding and management. The Federal Energy Regulatory Commission (FERC) exercised an authority to require a surcharge on interstate pipeline gas volumes to support consumer-focused RD&D for the natural gas industry. The FERC-approved surcharge in 1978 was equal to 0.12 cents per Mcf, rising to 1.51 cents per Mcf a decade later.[4] This led to a research fund in excess of $200 million/year for an extended period, yielding over $3 billion over the life of the surcharge.

The GRI was established in 1976 as a private non-profit research organization charged with managing the funds. It was required to have a Board of Directors representing the natural gas industry, industrial consumers, and the public and to submit a research plan annually for FERC approval. Important features of this approach were applied research and development closely connected to industry operational and technology needs, a broad RD&D portfolio from production to end use, and the ability to make long-term commitments and attract cost-sharing based on an assured funding stream. GRI programs leveraged substantial industry matching funds.

Clearly, the GRI funding was substantially greater than the DOE's. Joint portfolio planning was performed regularly to ensure that the

**Figure 8.3 DOE Natural Gas Research Funding History**




Source: DOE Office of Fossil Energy.

programs were complementary. Box 8.1 shows the interplay between the early DOE support for unconventional natural gas RD&D, the sustained GRI effort to work with industry in developing and demonstrating unconventional natural gas production technology, and a synergistic time-limited tax credit for unconventional production. There has been a considerable and continuing return on a relatively modest RD&D investment.

However, in the wake of pipeline deregulation, the surcharge was ended. In a regulated environment, the surcharge was easily passed on by the pipeline companies to ratepayers. After pipelines became common carriers in 1992, large gas consumers could contract directly with natural gas producers. In this new marketplace, the surcharge, although small, became a competitive issue. The combination of "bottom line" pressures associated with competitive markets, the tendency of state regulators to eschew rate increases in competitive markets, and a number of "free riders" (primarily intrastate pipelines in Texas that did not pay the surcharge) resulted in phaseout of the surcharge between 2000 and 2004. The GRI ended as a research management organization through a merger, in 2000, with the Institute for Gas Technology to form the Gas Technology Institute (GTI). The GTI managed the phaseout of the FERC-approved program and today serves as a research-performing non-profit organization. Its budget is substantially less than that of GRI.

The Energy Policy Act of 2005 established the RTF to support a 10-year $500 million research program (see Table 8.1) with a narrower research scope than had been the case for GRI:

the Ultra-Deepwater and Unconventional Natural Gas and Other Petroleum Resources Research Program. It is focused exclusively on exploration and production, including associated environmental impacts. The RTF draws its funding from a small fraction of royalties paid to the Federal government for oil and gas production leases of Federal on-shore and off-shore tracts. The program structure has many similarities to that of GRI: 75% of the funds are managed by a non-profit research management organization, the Research Partnership to Secure Energy for America (RPSEA); an annual program plan is approved by the Federal government, in this case the DOE; there are specific industry cost-sharing requirements; in principle, the mandatory funding allows for long-term stable funding of projects in collaboration with industry. Unfortunately, the advantages of stable funding have been more difficult to capture in this case since, as seen in Table 8.1, there have been persistent attempts to terminate the program.

**FINDING**

**The elimination of the rate-payer funded RD&D program was not compensated by increased DOE appropriations or by the RTF. The total public and public-private funding for natural gas research is down substantially from its peak and is more limited in scope, even as natural gas takes a more prominent role in a carbon-constrained world.**

The GRI and the RTF research models highlight the value of federally sanctioned alternative research models, with industry-led portfolios and dedicated multi-year funding mechanisms, in those cases specifically for natural gas RD&D. This value is derived primarily from: consistent funding over time; significant opportunities for industry input in program development and technical project reviews; and active collaboration between government, industry, academic institutions, the national labs, and non-governmental organizations. GRI also had a significant analytical unit, used widely by industry and policy makers until it was eliminated in 2001, as the surcharge funding started phasing out. Such a role is not easily incorporated into the DOE applied energy offices.

Recently, the President's Council of Advisors on Science and Technology (PCAST) put forward a set of recommendations for Federal energy research and policy that draws upon this experience.[5] The PCAST first recommends an overall annual funding level for energy research programs of around $16 billion, an increase of $10 to $11 billion over the DOE funding level. To be effective, PCAST observed that the funding must be "long-term, stable, and have broad enough bipartisan support to survive changes of Administration" and, recognizing the intense pressures on the annual domestic discretionary budget, recommended further that the additional funding be found largely through "new revenue streams," analogous to the FERC surcharge or the RTF. The PCAST further suggested that there is value in the external management of a portion of these funds, with strong industry input particularly for the development and demonstration phases, allowing the DOE to focus on its core strengths of funding basic and translational research and to serve an oversight role for the externally managed funds. These recommendations would extend the alternative models for funding and managing natural gas research to the entire energy RD&D portfolio and carry a certain degree of irony given the demise of GRI stimulated by deregulation and the continuing pressures on the RTF.

**RECOMMENDATION**

**The Administration and Congress should support RD&D focused on environmentally responsible, domestic natural gas supply. This should entail both a renewed DOE program, weighted towards basic research, and a complementary industry-led program, weighted towards applied RD&D, that is funded through an assured funding stream tied to energy production, delivery and use. In particular, the RTF should be continued and increased in its allocation commensurate with the promise and challenges of unconventional natural gas.**

**Furthermore, consideration should be given to restoring such a public-private RD&D research model for natural gas transportation and end-uses as well.**

## NOTES

[1]In FY 2011, a new methane hydrates program will be initiated by the DOE Office of Basic Energy Sciences under the Geosciences Research program.

[2]FY 2009 – FY 2012 DOE Budget Request to Congress.

[3]DOE Office of Budget. FY 1978 to FY 1996, DOE Budget Requests to Congress; Gas Research Institute 1979–1983 to 1994–1998, Research and Development Plans. Chicago, Ill., Gas Research Institute.

[4]Process Gas Consumers Group, Petitioner, v. Federal Regulatory Energy Commission, Respondent. American Gas Association, Interstate Natural Gas Association of America, Fertilizer Institute, Gas Research Institute, Georgia Industrial Group, Intervenors. No. 88-1109. United States Court of Appeals, District of Columbia.

[5]President's Council of Advisors on Science and Technology, Report to the President on Accelerating the Pace of Change in Energy Technologies Through an Integrated Federal Energy Policy, November, 2010.

# Appendix 1A: Life-Cycle Climate Impacts from Fossil Fuel Use

While natural gas emits less $CO_2$ per unit of heat produced from combustion than coal or oil, the net effects on the climate of using fossil fuels depends on life-cycle greenhouse gas emissions (GHGs) in production, processing, delivery, storage, and use. Inter-fuel comparisons on a life-cycle basis then depend on the quantity of fugitive methane emissions (from oil and coal as well as natural gas) since methane is a potent GHG, on the relative $CO_2$ emissions of different fuels in use (e.g., in electric power generation or transport); and on the relative contributions of the different GHGs to climate effects. Unfortunately, some published life-cycle emissions analyses are either not comprehensive or do not use common assumptions, leading to invalid comparisons.

### Fugitive Emissions

The issue of fugitive emissions is receiving increased attention as a result of a new EPA draft inventory of U.S. Greenhouse Gas Emissions and Sinks.[1] It presents estimates of methane emissions from natural gas production, processing, transmission, and distribution that are roughly twice prior estimates. There is substantial uncertainty in, and disagreement about, these estimates, which are based on new emission factors that are not widely agreed upon among industry analysts.

Moreover, life-cycle studies are not always consistent, or thorough, in the way they incorporate the effect of fugitive emissions. For example, a comparative estimate by the Tyndall Centre excluded fugitive and vented methane emissions from natural gas production.[2] Life-cycle analysis of electric power by the DOE National Energy Technology Laboratory show greater methane emissions from "raw materials acquisition" per MWh for coal generation than for natural gas, though details of the calculation are not specified.[3] Another study by researchers at Cornell University[4] evaluated the GHG footprint of shale gas. While questions about the uncertainties in methane emissions were appropriately raised in this study, its conclusions were strongly influenced by unsubstantiated estimates of methane emissions during the flow-back period.[5]

Furthermore, studies that do consider fugitive emissions usually ignore the likely effect of economic incentives suppliers have to reduce methane leakage and venting in natural gas operations, gaining additional revenue from captured methane. The EPA Natural Gas STAR program and the Global Methane Initiative (formerly the Methane to Markets Partnership) have had success in encouraging voluntary action by producers to reduce methane emissions. It is reasonable to expect that this progress will continue, and this effect should be reflected in life-cycle analyses.

Consistent inter-fuel comparisons would be greatly aided by resolution of the wide and varied range of analyses and assumptions about life-cycle natural gas emissions, especially in view of the revised EPA inventory. An agreed process and outcome, with broad stakeholder input, would help instill confidence in the methane emissions factors for natural gas, as well as for coal mining, that are reported to and used by the Federal government in its inventories of GHGs and for other purposes. The EPPA simulations in Chapter 3 of this study incorporate methane leakage assumptions for coal and natural gas. However, awaiting clarification of inventory methods and measurements, the inter-fuel comparisons in Chapter 4 (gas vs. coal) and Chapter 5 (gas vs. oil) assume that differential methane leakage does not have a substantial effect on results.

### End-Use Efficiency

The impact of differing assumptions about the efficiency of end-use technologies is also confounding comparisons of the climate effect of different fuels. For example, a widely cited Carnegie-Mellon University comparative estimate[6] used average natural gas emissions factors for the current fleet of existing natural gas power plants rather than the factors associated with deployment of new natural gas combined cycle technology. Even less justified, results in the Cornell study for gas vs. coal in electric generation are based on the heat content of each.[7] In fact, replacement of coal by natural gas in U.S. electric generation (see Chapter 4) would involve the substitution of coal units with an average efficiency of 30% to 35% with gas combined cycle plants with efficiencies in the range of 45% to 55%. Similar corrections are required to take account of differential efficiency of fuels in combustion engines used in transport vehicles (see Chapter 5).

### Relative Climatic Effect

Finally, evaluation of alternative mitigation measures requires a set of relative weighting factors for comparing the climatic effects of emissions of $CO_2$, methane and other GHGs. For this purpose, it would be desirable to have estimates of the present value of the net future damage caused by an additional ton of each GHG, emitted today. Such a procedure would require the development of an economic damage function that could project the future economic costs and benefits of GHG abatement, and the choice of a discount rate to compare short-term and longer-term impacts. The uncertainties in projections of climate change and its effects over time, and the extreme difficulties of damage estimation, present a challenge for estimating weighting factors in this way. Proposed alternatives would use the relative impact of emissions of various gases on temperature change at some future date, or the relative effect on the cost of meeting a specified limit on temperature change, but these approaches run into similar problems of data and analysis.

In lieu of such measures of net future damage, climate effect, and costs of control, the Intergovernmental Panel on Climate Change (IPCC) has adopted a measure of the effect of different GHGs early in the chain of consequences: the relative influence of emissions on the Earth's radiative balance. This is the Global Warming Potential (GWP), which is the integral over time of radiative "forcing," where the weighting factors for other gases are stated in relation to $CO_2$, which is defined to have a GWP of 1.0.[8] Because the various GHGs have different lives in the atmosphere (e.g., on the scale of a decade for methane, but centuries for $CO_2$), the calculation of GWPs depends on the integration period. Early studies calculated this index for 20-, 100-, and 500-year integration periods.[9] The IPCC decided to use the 100-year measure, and it is a procedure followed by the U.S. and other countries over several decades.[10] An outlier in this domain is the Cornell study which recommends the application of the 20-year value in inter-fuel comparison.[11] A 20-year GWP would emphasize the near-term impact of methane but ignore serious longer-term risks of climate change from GHGs that will remain in the atmosphere for hundreds to thousands of years, and the 500-year value would miss important effects over the current century. Methane is a more powerful GHG than $CO_2$, and its combination of potency and short life yields the 100-year GWP used in this study.[12]

## NOTES

[1]U.S. Environmental Protection Agency, "DRAFT — Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990–2009, Chapter 3: Energy, available at http://www.epa.gov/climatechange/emissions/downloads11/US-GHG-Inventory-2011-Chapter-3-Energy.pdf.

[2]Tyndall Centre, University of Manchester, Shale Gas: a provisional assessment of climate change and environmental impacts, January 2011, pp. 6 and 37.

[3]James, R., and T. Skone (2010). Life Cycle Analysis: Power Studies Compilation Report, National Energy Technology Laboratory, October. http://www.netl.foe.gov/energy-analyses/refshelf/PubDetails.aspx?Action=View&Publd=358.

[4]Howarth, R. et al (2011). Methane and the greenhouse-gas footprint of natural gas from shale formations, *Climatic Change*, 106: 679-690.

[5]The largest leakage as a percentage of lifetime production as estimated by Howarth et al., op (Table 1) is for methane emitted in the Haynesville shale. It is attributed to an average from Eckhard M. et al (2009). IHS U.S. Industry Highlights, February–March. However, though the cited publication provides figures for natural gas production at Haynesville, the only example of production testing during the flow-back period stated that methane was not emitted to the atmosphere and the well was "producing to sales."

[6]Jaramillo, P., et al. (2007). "Comparative Life-Cycle Air Emissions of Coal, Domestic Natural Gas, LNG and SNG for Electricity Generation," *Environmental Science and Technology*, 41: 6290-6296.

[7]Howarth R., et al., op cit. The higher the efficiency of generation, the less $CO_2$ is emitted per kilowatt hour of electricity produced. Additional calculations are provided in Electronic Supplemental Materials to the paper, but those fail to recognize the higher efficiency of natural gas combined cycle units that would replace coal generation.

[8]For criticism of, and alternatives to, this procedure see Reilly, J., K. Richards (1993). Climate Change Damage and the Trace Gas Index Issue, *Environmental Resource Economics* 3:41-61; Schmalensee, R. (1993). Comparing Greenhouse Gases for Policy Purposes, *The Energy Journal* 14: 245-255; R. Eckaus (1992). Comparing the Effects of Greenhouse Gases on Global Warming, *The Energy Journal* 13: 25-35; and Manne, A., and R. Richels (2001). An Alternative Approach to Establishing Trade-Offs among Greenhouse Gases, *Nature* 410: 675-677.

[9]Lashof, D. and D. Ahuja (1990). The Relative Contributions of Greenhouse Gases to Global Warming, *Nature* 344: 529-531.

[10]One comparison of methods finds that the 100-year GWP yields a result that is roughly consistent with measures based on the relative effect on temperature change or on the cost of meeting a future target. See D. Johansson (2011). Economics- and physical-based metrics for comparing greenhouse gases, *Climatic Change* (http://www.springerlink.com/content/100247/?Content+Status=Accepted).

[11]Howarth et al, *op cit*.

[12]Even though the GWP is at best a very approximate indicator of the climatic effects of different greenhouse gases, there are proposals to extend the scope of the calculation — including knock-on effects on components of the Earth system like heating and cooling aerosols, ozone and the carbon cycle — e.g., Shindell, D., et al. (2009). Improved Attribution of Climate Forcing to Emissions, *Science* 236: 716-718). If included in the definition these phenomena would increase the GWP of methane somewhat while greatly increasing the uncertainty in its estimate.

# Appendix 2A: Additional Data Concerning Natural Gas Resources

This appendix contains additional data tables and maps for natural gas resources. It is intended to supplement the material shown in the main text, with additional information on global resources and a detailed breakdown of various resource estimates for the U.S. Further background on resource definitions is provided in Supplementary Paper SP 2.2, which is available on the MITEI website at web.mit.edu/mitei/research/studies/documents/natural-gas-2011/supplementals.pdf. SP 2.2 also contains detailed descriptions of the natural gas resources of the five largest global gas resource owners: the U.S., Canada, Russia, Iran, and Qatar.

**Table 2A.1 Recoverable Resources by EPPA Regions. The world P10 and P90 numbers were found by statistical aggregation. Gas – Tcf**

| Region | EPPA Region | Reserves | Reserve Growth | | | Conventional Undiscovered | | | Total Undiscovered Resources[i] | | | Remaining Recoverable Resource | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | Mean | P10 | P90 | Mean | P10 | P90 | Mean | P10 | P90 | Mean | P10 | P90 |
| North America | U.S. | 279[ii] | 209 | 161 | 270 | 742 | 410 | 1,174 | 1,661 | 1,015 | 2,442 | 2,149 | 1,455 | 2,990 |
| | Canada | 98 | 29 | 22 | 37 | 219 | 104 | 356 | 695 | 419 | 1,013 | 822 | 539 | 1,148 |
| Latin America | Brazil | 8 | 90 | 69 | 116 | 251 | 89 | 425 | 251 | 89 | 425 | 349 | 167 | 549 |
| | Mexico | 14 | 19 | 15 | 25 | 61 | 27 | 101 | 61 | 27 | 101 | 95 | 56 | 139 |
| | Rest of Americas | 250 | 106 | 81 | 137 | 447 | 128 | 795 | 447 | 128 | 795 | 803 | 459 | 1,181 |
| Europe and FSU | EU27 and Norway | 191 | 150 | 116 | 194 | 393 | 108 | 761 | 393 | 108 | 761 | 734 | 414 | 1,145 |
| | Russia | 1,680 | 424 | 326 | 547 | 1,341 | 543 | 2,287 | 1,341 | 543 | 2,287 | 3,445 | 2,550 | 4,513 |
| | Central Asia and Rest of Europe | 338 | 94 | 72 | 121 | 511 | 226 | 831 | 511 | 226 | 831 | 944 | 636 | 1,291 |
| Middle East | Middle East | 2,514 | 547 | 421 | 705 | 1,632 | 805 | 2,550 | 1,632 | 805 | 2,550 | 4,693 | 3,740 | 5,769 |
| Asia and Pacific | China | 80 | 13 | 10 | 16 | 117 | 50 | 193 | 117 | 50 | 193 | 209 | 140 | 290 |
| | India | 38 | 16 | 12 | 20 | 34 | 15 | 56 | 34 | 15 | 56 | 88 | 66 | 114 |
| | Dynamic Asia | 192 | 102 | 79 | 132 | 194 | 95 | 306 | 194 | 95 | 306 | 488 | 366 | 630 |
| | Rest of E. Asia | 66 | 44 | 34 | 56 | 134 | 52 | 236 | 134 | 52 | 236 | 244 | 151 | 358 |
| | Australia & Oceania | 39 | 40 | 31 | 51 | 149 | 68 | 239 | 149 | 68 | 239 | 228 | 138 | 329 |
| Africa | Africa | 489 | 112 | 86 | 145 | 439 | 246 | 653 | 439 | 246 | 653 | 1,040 | 821 | 1,286 |
| **World** | **World** | **6,275** | **1,994** | **1,536** | **2,573** | **6,665** | **3,729** | **10,104** | **8,060** | **4,770** | **11,934** | **16,329** | **12,581** | **20,781** |

Notes on Table 2A.1

[i]The entries here include unconventional and conventional resources. Unconventional resources have only been included for the U.S. and Canada.

[ii]The 279 Tcf of reserves in the U.S. is the sum of 245 Tcf of proved reserves and 34 Tcf of stranded reserves, primarily located in Alaska.

**Table 2A.2 Undiscovered Recoverable Unconventional Natural Gas Resources Adopted in This Study for North America. The P10 and P90 numbers give the 10% and 90% probability estimates.**

**Gas – Tcf**

| | Technically Recoverable Unconventional Gas (excluding Proved Reserves) | | |
|---|---|---|---|
| | **Mean** | **P90** | **P10** |
| U.S. | | | |
| Tight | 173 | 118 | 239 |
| Shale | 631 | 418 | 871 |
| CBM | 115 | 69 | 162 |
| **Total U.S.** | **919** | **605** | **1,272** |
| Canada | | | |
| Tight | - | - | - |
| Shale | 443 | 294 | 611 |
| CBM | 33 | 20 | 46 |
| **Total Canada** | 476 | 314 | 657 |
| **North America** | **1,395** | **1,042** | **1,829** |

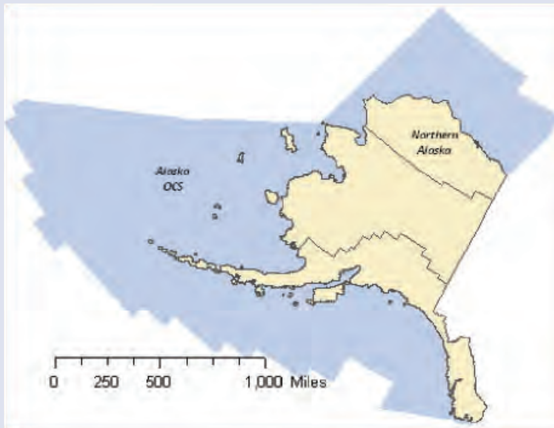
**Table 2A.3 GIIP for Global Unconventional Resources from Rogner's Study (Rogner 1997). The recoverable resource, based on production data in the U.S., may lie in the 10% to 35% range of GIIP.**

**Gas – Tcf**

| **Region** | **Region Code** | **Unconventional Gas Initially in Place** | | | |
|---|---|---|---|---|---|
| | | **Tight gas** | **Shale gas** | **Coal Bed Methane** | **Total** |
| North America | NAM | 1,371 | 3,840 | 3,017 | 8,228 |
| Former Soviet Union | FSU | 901 | 627 | 3,957 | 5,485 |
| Centrally Planned Asia and China | CPA | 353 | 3,526 | 1,215 | 5,094 |
| Pacific OECD | PAO | 705 | 2,312 | 470 | 3,487 |
| Latin America | LAM | 1,293 | 2,116 | 39 | 3,448 |
| Middle East and North Africa | MEA | 823 | 2,547 | 0 | 3,370 |
| Sub-Saharan Africa | AFR | 784 | 274 | 39 | 1,097 |
| Western Europe | WEU | 353 | 509 | 157 | 1,019 |
| Other Pacific Asia | PAS | 549 | 313 | 0 | 862 |
| Central and Eastern Europe | EEU | 78 | 39 | 118 | 235 |
| South Asia | SAS | 196 | 0 | 39 | 235 |
| **World** | | **7,406** | **16,103** | **9,051** | **32,560** |

Source: Rogner 1997

## Figure 2A.1 Selected U.S. Conventional Gas Basins




The panel on the left shows the Northern Alaskan province and the Outer Continental Shelf (OCS).

The bottom panel shows the L48 basin boundaries: the main regions and the Atlantic, Pacific, and Gulf of Mexico OCSs. The basins indicated contain the majority of the conventional undiscovered technically recoverable resource, with the Gulf Coast region containing 60% of the onshore L48 resource according to the USGS. The Southwestern Wyoming basin (also called the Green River Basin) primarily contains tight gas resources.


Source: Shape files used from USGS NOGA program website and from MMS (now BOEMRE) website.

**Table 2A.4 Basins with Significant Conventional Gas Undiscovered Technically Recoverable Resource (UTRR) for NPC, USGS/MMS and PGC. As PGC does not separately provide data for conventional and tight gas, the USGS and NPC tight gas assessments have also been included. (See Table 2A.8 for further details on tight gas.) PGC Probable resources are the equivalent to reserve growth while the sum of Possible and Speculative are that of UTRR.**

**Gas – Tcf**

| U.S. Region | Basin/Province | NPC 2003 | | USGS/MMS 2002–08/2006 | | PGC 2009 | |
|---|---|---|---|---|---|---|---|
| | | Conventional | Tight Gas | Conventional | Tight Gas | Probable | Possible and Speculative |
| Eastern Region | Appalachian Basin | 6.2 | 34.8 | 4.3 | 45.4 | 11.6 | 17.5 |
| | Michigan and Illinois Basin | 7.8 | - | 4.4 | - | 0.3 | 0.3 |
| | Other | 1.5 | - | 1.9 | - | 0.4 | 15.2 |
| | **Total** | **15.5** | **34.8** | **10.6** | **45.4** | **12.3** | **33.0** |
| Midcontinent Region | Anadarko Basin | 21.0 | - | 14.2 | - | 21.4 | 29.2 |
| | Arkoma Basin | 3.8 | - | 2.5 | - | 1.3 | 3.4 |
| | Other | 2.1 | - | 2.9 | - | 0.5 | 1.8 |
| | **Total** | **26.9** | **-** | **19.6** | **-** | **23.2** | **34.4** |
| Gulf Coast | E. Texas, LA-MS Salt Basin and Florida Peninsula | 29.2 | 5.9 | 31.2 | 6.0 | 32.4 | 50.5 |
| | Western Gulf Basin | 47.9 | 2.6 | 68.1 | - | 38.6 | 69.2 |
| | **Total** | **77.1** | **8.5** | **99.2** | **6.0** | **71.0** | **119.7** |
| W. Texas and E. New Mexico | Permian and Bend Arch-Fort Worth Basin | 19.6 | - | 5.7 | - | 10.7 | 25.4 |
| | Other | - | - | 0.1 | - | - | - |
| | **Total** | **19.6** | **-** | **5.8** | **-** | **10.7** | **25.4** |
| Rocky Mountains and Northern Great Plains | SW Wyoming Basin | 4.7 | 65.8 | 2.4 | 80.5 | 10.9 | 15.5 |
| | Wind River Basin | 1.6 | - | 0.5 | 1.7 | 5.0 | 9.8 |
| | Montana Thrust Belt | 8.3 | - | 0.1 | - | 0.0 | 12.6 |
| | Other | 3.4 | | 14.5 | 8.2 | 35.5 | 15.9 |
| | **Total** | **18.0** | **65.8** | **17.5** | **90.4** | **51.4** | **53.7** |
| Colorado Plateau and Basin and Range | Uinta-Piceance Basin | 2.1 | 23.5 | 0.2 | 18.8 | | 49.7 |
| | Paradox and Great Basin | 2.7 | - | 4.3 | - | 0.6 | 4.1 |
| | San Juan and Santa Fe Rift | 0.7 | 21.0 | 0.5 | 26.1 | 5.6 | 7.0 |
| | Other | - | - | 0.4 | | 12.6 | 6.0 |
| | **Total** | **5.5** | **44.5** | **5.4** | **44.9** | **18.7** | **66.8** |
| Pacific Region | San Joaquin Basin | 5.9 | - | 1.8 | - | 1.7 | 10.0 |
| | Other | 4.5 | 11.9 | 6.6 | - | 1.0 | 17.4 |
| | **Total** | **10.4** | **11.9** | **8.3** | | **2.7** | **27.4** |
| Pacific Offshore/OCS | Pacific Offshore | 20.7 | - | 18.3 | - | 0.1 | 15.8 |
| Gulf of Mexico/OCS | GOM Offshore | 244.4 | - | 232.5 | - | 15.6 | 77.7 |
| Atlantic Offshore/OCS | Atlantic Offshore | 32.8 | - | 37.0 | - | 0.0 | 13.0 |
| **Lower 48** | **Total** | **486.4** | **175.2** | **454.2** | **189.9** | **205.7** | **466.8** |
| Alaska | Northern Alaska | 72.1 | - | 204.6 | - | 26.2 | 42.0 |
| | Other | 3.7 | - | 7.6 | - | 4.7 | 2.1 |
| | **Total Onshore** | **75.8** | **-** | **212.2** | **-** | **30.9** | **44.1** |
| | Alaska Offshore/OCS | 125.2 | - | 132.1 | - | 2.4 | 65.7 |
| | **Total** | **201.0** | **-** | **344.3** | **-** | **33.3** | **109.8** |
| **U.S.** | **TOTAL** | **687.4** | **175.2** | **798.5** | **189.9** | **239.0** | **576.6** |

**Figure 2A.2 U.S. Hydrocarbon Provinces with Tight Gas Plays. These plays are concentrated in a few basins that are highlighted. Some of these basins, such as the East Texas and Western Gulf Basins, have also been significant producers of conventional natural gas. Other basins, such as Southwestern Wyoming, are dominated by unconventional resources.**

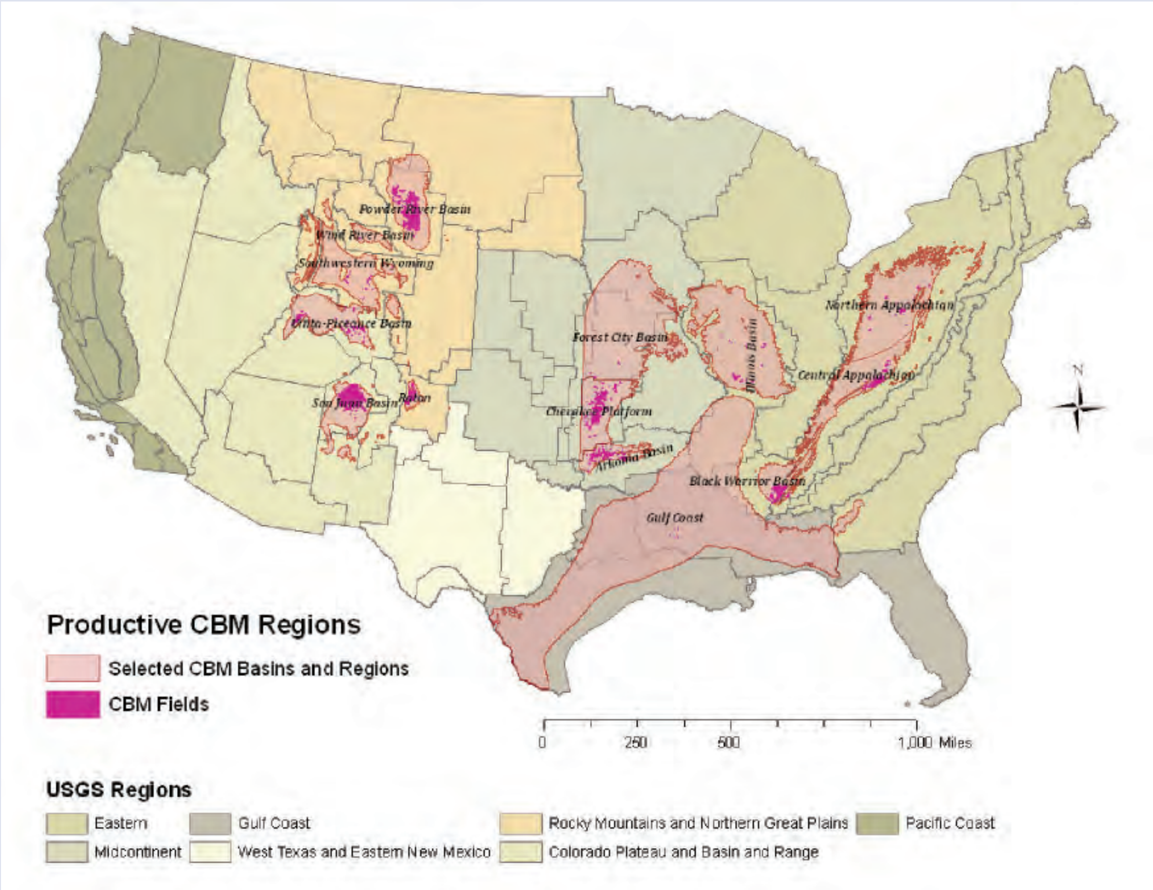

Source: Shape files used from USGS NOGA program website and EIA website.

**Table 2A.5 Tight Gas Mean Estimates of Undiscovered Recoverable Resources by Basin, by Agency, and Year. PGC reports its tight gas estimates with conventional gas.**

**Gas – Tcf**

| U.S. Region | Basin/Province | Plays | NPC 2003 | EIA 2007 | USGS 2002–08 | EIA 2009 | ICF March, 09 |
|---|---|---|---|---|---|---|---|
| Eastern Region | Appalachian Basin | | 34.8 | 56.0 | 45.4 | 54.3 | 34.8 |
| Midcontinent Region | Anadarko Basin | | - | 13.4 | - | 12.7 | - |
| | Arkoma Basin | | - | 4.1 | - | 3.6 | - |
| | **Total** | | **-** | **17.5** | **-** | **16.3** | **-** |
| Gulf Coast | E. Texas and LA-MS Salt Basin | | 5.9 | 31.6 | 6.0 | 29.1 | 25.2 |
| | Western Gulf Basin | | 2.6 | 14.6 | - | 13.3 | 4.6 |
| | **Total** | | **8.5** | **46.2** | **6.0** | **42.4** | **29.8** |
| W. Texas and E. New Mexico | Permian Basin | | - | 13.8 | - | 13.4 | - |
| Rocky Mountains and Northern Great Plains | South Western Wyoming Basin | | 65.8 | 75.4 | 80.5 | 72.2 | 38.8 |
| | Wind River Basin | | - | 19.6 | 1.7 | 19.6 | - |
| | N. Cent. Montana | | 5.8 | 4.8 | 6.1 | 4.7 | 5.8 |
| | Williston Basin | | 1.8 | - | 0.1 | - | 1.8 |
| | Denver Basin | | 2.0 | 9.2 | 2.0 | 9.1 | 2.0 |
| | **Total** | | **75.4** | **109.0** | **90.4** | **105.6** | **48.4** |
| Colorado Plateau and Basin and Range | Uinta-Piceance Basin | *Piceance Basin* | 9.7 | 24.3 | 5.0 | 41.0 | 11.7 |
| | | *Uinta Basin* | 13.8 | 15.9 | 13.8 | 15.6 | 15.8 |
| | | *Total* | 23.5 | 40.2 | 18.8 | 56.6 | 27.5 |
| | San Juan Basin | | 21.0 | 14.9 | 26.1 | 14.5 | 21.0 |
| | **Total** | | **44.5** | **55.1** | **44.9** | **71.1** | **48.5** |
| Pacific Region | Western Oregon Basin | | 11.9 | 6.4 | 2.1 | 6.5 | 11.9 |
| **Lower 48** | **Total** | | **175.2** | **304.2** | **189.9** | **309.5** | **174.3** |
| Alaska | | | - | - | - | - | - |
| **U.S.** | **TOTAL** | | **175.2** | **304.2** | **189.9** | **309.5** | **174.3** |

## Figure 2A.3 U.S. CBM Basins and Fields




Source: GIS Shape files used from USGS NOGA program website and EIA website.

## Table 2A.6 CBM Mean Estimates of UTRR by Basin, Agency, and Year

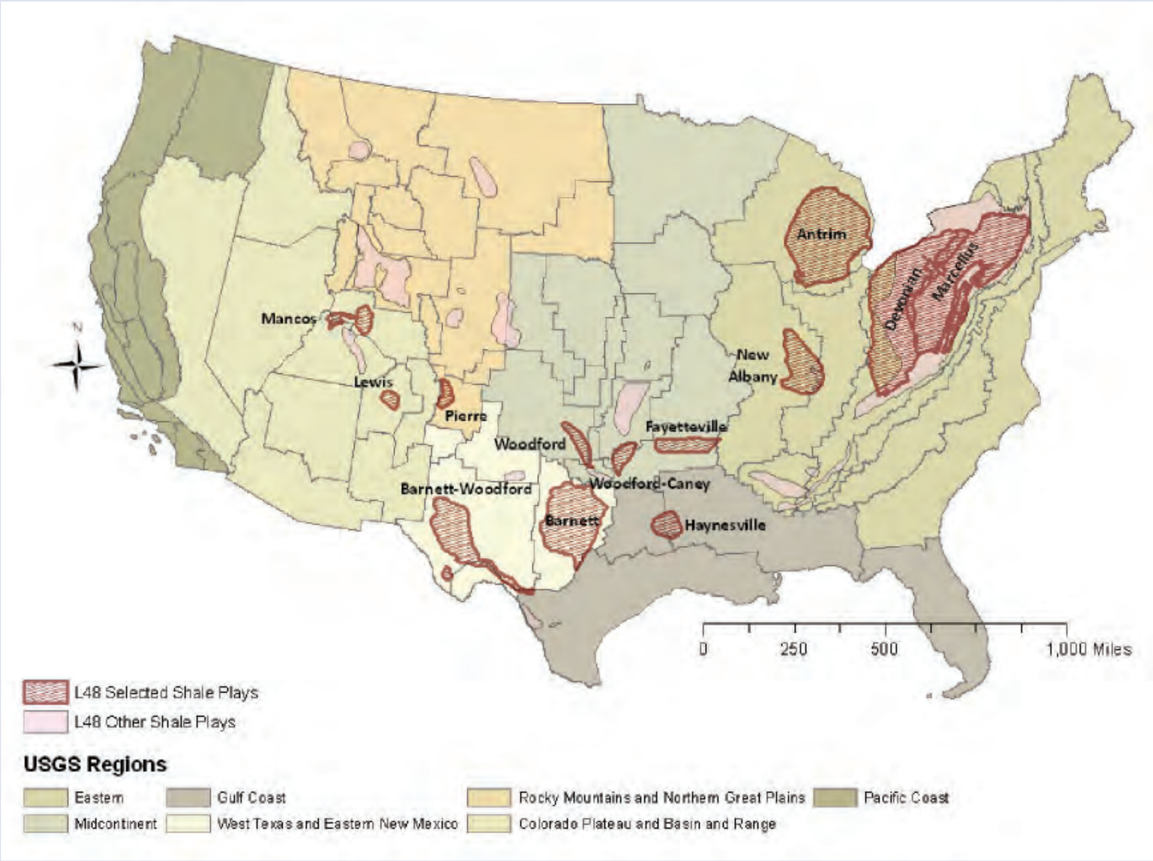
### Gas – Tcf

| U.S. Region | Basin/Province | Basin/Province | NPC 2003 | EIA 2007 | USGS 2002–08 | PGC 2008 | EIA 2009 | ICF March, 09 |
|---|---|---|---|---|---|---|---|---|
| Eastern Region | Appalachian Basin | *C. Appalachian* | 3.5 | 3.6 | 3.6 | 10.6 | 2.8 | 3.5 |
| | | *N. Appalachian* | 4.7 | 4.8 | 4.8 | 2.4 | 1.5 | 4.7 |
| | | *Total* | 8.2 | 8.4 | 8.4 | 12.9 | 4.3 | 8.2 |
| | Black Warrior Basin | | 4.5 | 4.8 | 7.1 | 4.4 | 3.5 | 4.5 |
| | Illinois Basin | | 1.6 | 0.6 | 0.4 | 7.7 | 0.6 | 1.6 |
| | **Total** | | **14.3** | **13.8** | **15.9** | **25.0** | **8.4** | **14.3** |
| Midcontinent Region | Forest City Basin | | 0.4 | 2.4 | 0.5 | 6.1 | 1.9 | 0.4 |
| | Cherokee Platform | | 1.9 | - | 1.9 | 2.8 | - | 1.9 |
| | Arkoma Basin | | 2.6 | 3.2 | 2.6 | 1.8 | 4.1 | 2.6 |
| | **Total** | | **4.9** | **5.6** | **5.0** | **10.7** | **5.9** | **4.9** |
| Gulf Coast | E. Texas, W. Gulf, and LA-MS Salt Basin | *Gulf Coast Coal Region* | - | - | 4.1 | 3.4 | - | - |
| W. Texas and E. New Mexico | Bend Arch-Fort Worth Basin | *Southwestern Coal Region* | - | - | - | 5.8 | - | - |
| Rocky Mountains and Northern Great Plains | Raton Basin | | 2.0 | 4.0 | 1.6 | 4.3 | 5.5 | 1.9 |
| | Wind River Basin | | 0.4 | - | 0.3 | 2.5 | - | 0.4 |
| | South Western Wyoming Basin | | 2.0 | 1.7 | 1.5 | 8.6 | 3.7 | 2.0 |
| | Powder River Basin | | 20.0 | 26.8 | 14.3 | 18.5 | 19.6 | 26.6 |
| | Others[i] | | - | - | - | 1.1 | - | - |
| | **Total** | | **24.4** | **32.5** | **17.7** | **35.0** | **28.8** | **30.9** |
| Colorado Plateau and Basin and Range | Uinta-Piceance Basin | *Piceance Basin* | 3.8 | 7.9 | 0.4 | 5.5 | 6.3 | 3.7 |
| | | *Uinta Basin* | 2.3 | 4.2 | 2.0 | w/Pic | 3.3 | 2.2 |
| | | *Total* | 6.1 | 12.1 | 2.4 | 5.5 | 9.6 | 5.9 |
| | Paradox Basin | | - | - | - | 2.8 | - | - |
| | San Juan Basin | *San Juan Fruitland* | 8.0 | 18.1 | 23.6 | 6.7 | 15.2 | 8.0 |
| | | *San Juan Menefee* | 0.7 | 0.2 | 0.7 | - | 0.2 | 0.4 |
| | | *Total* | 8.7 | 18.4 | 24.2 | 6.7 | 15.4 | 8.4 |
| | **Total** | | **14.8** | **30.5** | **26.6** | **15.0** | **25.0** | **14.3** |
| Pacific Region | Western Oregon Basin | | 0.7 | - | 0.7 | 2.6 | - | 0.7 |
| **Lower 48** | **Total** | | **58.9** | **82.4** | **69.9** | **98.7** | **68.1** | **64.9** |
| Alaska | Northern Alaska | | 57.0 | - | 18.1 | 57.0 | - | 57.0 |
| **U.S.** | **TOTAL** | | **115.9** | **82.4** | **87.9** | **155.7** | **68.1** | **121.9** |

Notes on Table 2A.6

[i]Includes Denver Basin and Big Horn Basin.

**Figure 2A.4 Selected U.S. Shale Gas Plays, Superimposed on USGS Basins and Regions**




Source: Shape files used from USGS NOGA program website and EIA website.

## Table 2A.7 Shale Gas Mean Estimates of Undiscovered Recoverable Resources by Basin, Agency, and Year

### Gas – Tcf

| U.S. Region | Basin/Province | Shale Plays | NPC 2003 | USGS 2002–08 | EIA 2008 | ICF 2008 | EIA 2009 | PGC 2008 | ICF Mar, 09 |
|---|---|---|---|---|---|---|---|---|---|
| Eastern Region | Appalachian Basin | *Devonian – Low Pressure* | 17.0 | 12.2 | 14.4 | 30.6 | 13.1 | | 30.6 |
| | | *Marcellus* | - | - | - | 63.0 | 38.3 | 227.3 | 289.7 |
| | | *Huron* | - | - | - | 20.0 | - | | 20.0 |
| | | *Total* | 17.0 | 12.2 | 14.4 | 113.6 | 51.4 | 227.3 | 340.3 |
| | Michigan Basin | *Antrim* | 7.4 | 7.5 | 10.6 | 4.0 | 10.0 | 5.9 | 4.0 |
| | Illinois Basin | *New Albany* | 1.8 | 3.8 | 2.0 | 3.2 | 3.1 | 5.4 | 3.2 |
| | Cincinnati Arch | *New Albany, Chattanooga* | 1.3 | - | 0.8 | 2.3 | 1.1 | - | 2.3 |
| | **Total** | | **27.5** | **23.5** | **27.8** | **123.1** | **65.6** | **238.6** | **349.8** |
| Midcontinent Region | Arkoma Basin | *Fayetteville* | - | - | 29.2 | 58.0 | 29.2 | 110.5 | 86.3 |
| | | *Woodford* | - | - | 15.8 | 53.0 | 19.7 | | 61.9 |
| | | *Total* | - | - | 45.0 | 110.3 | 48.9 | 110.5 | 148.2 |
| | Anadarko Basin | *Woodford-Caney* | - | - | - | - | 7.1 | 2.1 | - |
| | **Total** | | **-** | **-** | **45.0** | **111.0** | **56.0** | **112.6** | **148.2** |
| Gulf Coast | E. Texas and LA-MS Salt Basin | *Haynesville* | - | - | - | 31.0 | 71.6 | 112.4 | 102.2 |
| W. Texas and E. New Mexico | Bend Arch-Fort Worth Basin | *Barnett* | 7.0 | 26.2 | 38.0 | 107.0 | 59.7 | 59.3 | 107.4 |
| | Permian Basin | *Barnett and Woodford* | - | 35.1 | - | 10.0 | - | 3.9 | 10.0 |
| | **Total** | | **7.0** | **61.3** | **38.0** | **117.0** | **59.7** | **63.2** | **117.4** |
| Rocky Mountains and Northern Great Plains | Raton Basin | *Pierre* | - | - | - | 2.0 | - | - | 2.0 |
| | Williston Basin | *Niobrara* | - | - | 3.9 | * | 3.9 | - | * |
| | **Total** | | **-** | **-** | **3.9** | **2.0** | **3.9** | **-** | **2.0** |
| Colorado Plateau and Basin and Range | Uinta-Piceance Basin | *Mancos* | - | - | - | * | - | 60.2 | * |
| | Paradox Basin | *Gothic* | - | - | - | 1.0 | - | - | 1.0 |
| | San Juan Basin | *Lewis* | - | - | 10.4 | * | 10.5 | 4.5 | * |
| | **Total** | | **-** | **-** | **10.4** | **1.0** | **10.5** | **64.7** | **1.0** |
| Pacific Region | San Joaquin Basin | *McClure* | 0.3 | - | - | 0.3 | - | - | 0.3 |
| **Lower 48** | **Total** | | **34.7** | **84.8** | **125.0** | **385.4** | **267.2** | **615.9** | **720.9** |
| Alaska | | | - | - | - | - | - | - | - |
| **U.S.** | **TOTAL** | | **34.7** | **84.8** | **125.0** | **385.4** | **267.2** | **615.9** | **720.9** |

*Assessed with tight gas.

## Table 2A.8 Shale Volumetric Properties for U.S. Shale Plays Included in the Shale Resource Volumes in This Study

| Play | Assessed Gross Play Area | Basin Average Shale Thickness | Shale Volume | Unrisked Gas in Place | Risked Gas in Place | Assessment Well Spacing | Recovery Factor at this Spacing | Technical Recovery at this Spacing |
|---|---|---|---|---|---|---|---|---|
| | sq. mi. | Ft | cu.miles | Tcf | Tcf | Acres | | Tcf |
| Fort Worth Barnett | 7,755 | 249 | 366 | 1,158 | 538 | 40 | 0.20 | 107 |
| Appalachian Marcellus | 35,725 | 140 | 947 | 1,635 | 966 | 80 | 0.30 | 290 |
| Arkoma Fayetteville | 9,144 | 188 | 326 | 309 | 216 | 40 | 0.40 | 86 |
| Arkoma Woodford | 11,628 | 83 | 183 | 719 | 169 | 40 | 0.37 | 62 |
| West Texas Barnett | 5,107 | 440 | 426 | 1,302 | 205 | 80 | 0.05 | 10 |
| Louisiana Haynesville | 7,189 | 219 | 298 | 753 | 433 | 80 | 0.24 | 104 |

Source: ICF

## Table 2A.9 A Selection of Key Geological and Geophysical Properties of Shale Plays

| Basin | | Ft. Worth | Arkoma | Arkoma | Michigan | Illinois | Permian | Appalachian | Appalachian | Louisiana | Warrior |
|---|---|---|---|---|---|---|---|---|---|---|---|
| Shale Play | | Barnett (non-core) | Fayetteville | Woodford | Antrim | New Albany | Woodford | Marcellus | Huron | Haynesville | Floyd |
| Well Type | | Horizontal | Horizontal | Horizontal | Vertical | | Vertical | Vertical | | Horizontal | Vertical |
| Geologic Age | | Devonian | Devonian | Mississippian | Devonian | Devonian | Devonian | Devonian | Devonian | Jurassic | Mississippian |
| Vertical Depth | Ft | 4,500–9,000 | 1,500–6,500 | 6,000–12,000 | 600–2,400 | 3,000 | 8,000–12,000 | 5,000–8,500 | 3,500–5,500 | 10,000–13,000 | 6,500–9,000 |
| Gross Thickness | Ft | 200–800 | 50–400 | 100–300 | 150 | 100–300 | 400–800 | 50–200 | 150–200 | 200+ | 100–300 |
| Pressure Gradient | Psi/ft | 0.45–0.50 | 0.44 | | | 0.43 | | | | 0.50–0.70 | |
| Origin of Natural Gas | | Thermogenic | Thermogenic | Thermogenic | Biogenic | Thermogenic | Thermogenic | Thermogenic | Thermogenic | Thermogenic | Thermogenic |
| Total Organic Content | % | 3.5–5.0+ | 2.0–5.0+ | 3.0–10.0 | 0.3–20.0+ | 1.0–25.0 | 4.0–7.0 | 2.0–6.0 | 3.5 | 3.0–5.0 | 1.8 (0.5–10.0) |
| Vitrinite Reflectance | %Ro | 1.0–2.2 | 1.5–4.0 | 1.1–3.0 | 0.4–0.6 | < 0.7 | | 1.0–2.5 | | | 0.92–1.6 |
| Silica Content | % | 40–60 | 40–60 | 60–80 | | | | | | | |
| Gas Content | Scf/ton | 300–500 | | | 40–100 | | | | | | |
| Gas-in-Place/sq. mi | Bcf/Sq. mi | 50–250 | 30–80 | 35–130 | 6.0–15.0 | | 100–500 | | | 150–250 | |
| Reserves per Well | Bcf | 1.5–3.0+ | 1.6+ | 3.0–5.0 | 0.2–0.6 | | 3 | 0.8 (vert) | 0.8–1.5 | 3.0–6.5 | |
| General Gas Wetness | | Wet | | Wet | | Wet | | Wet | | | Dry |
| $CO_2$ | % | | | | Up to 20% | 0%–5% | | | | | negl. |
| Methane | % | | | | | | | 80–95 | | | |
| Heating Content | Btu/cf | 1,000 - 1,400 | | | | | | 900–1,300 | | | |

Source: Reproduced from Table 16 in Vidas and Hugman 2008

## Table 2A.10 Volumetric Properties of Selected Shale Plays in Canada

| Play | Assessed Gross Play Area | Basin Average Shale Thickness | Shale Volume | Unrisked Gas in Place | Risked Gas in Place | Assessment Well Spacing | Recovery Factor at this Spacing | Technical Recovery at this Spacing |
|---|---|---|---|---|---|---|---|---|
| | sq. mi. | Ft | cu.miles | Tcf | Tcf | Acres | | **Tcf** |
| BC Devonian Horn River Muskwa | 5,175 | 400 | 392 | 1,007 | 771 | 80 | 0.20 | **154** |
| WCSB Montney | 38,346 | 878 | 6,376 | 4,651 | 1,536 | 80 | 0.15 | **230** |

## Table 2A.11 Selected Geological and Geophysical Properties of Shale Plays in Canada

| Basin | | E. Canada | BC | BC |
|---|---|---|---|---|
| Shale Play | | Utica | Muskwa | Montney |
| Well Type | | Horizontal | Horizontal | Horizontal |
| Geologic Age | | Ordovician | Devonian | Triassic |
| Vertical Depth | Ft | 2,300–6,000 | 7,800–13,000 | 6,500–12,000 |
| Gross Thickness | Ft | 500 | 500 | 500 |
| Pressure Gradient | Psi/ft | .45–.60 | | |
| Origin of Natural Gas | | Thermogenic | Thermogenic | Thermogenic |
| Total Organic Content | % | 1.0–3.1 | 3.0 | 1.5–6.0 |
| Vitrinite Reflectance | %Ro | 1.3–3.0 | 2.8 | 0.8–2.5 |
| Silica Content | % | | 65 | |
| Gas-in-Place/sq. mi | Bcf/sq. mi | 75–350 | 180–320 | 75–100 |
| Reserves per Well | Bcf | 1,700 | 4,000+ | 2,000+ |
| $CO_2$ | % | none | | |
| Methane | % | 88–97 | | |
| Heating Content | Btu/cf | 1,027–1,136 | | |

Source: Reproduced from Table 16 in Vidas and Hugman 2008

**References:**

Rogner, H. H. 1997, "An Assessment of World Hydrocarbon Resources," *Annual Review of Energy and the Environment* 22 (1): 217–262.

Vidas, H., and B. Hugman. 2008, "Availability, Economics, and Production Potential of North American Unconventional Natural Gas Supplies," *The INGAA Foundation, Fairfax, Va.*

# Appendix 2B: Technical Note on Incorporating Supply Volume Sensitivity in Cost Curves

In this study, we emphasize the uncertainty inherent in all projections of naturally occurring energy resources, and capture this uncertainty in analytical form. This appendix summarizes the methodology employed to create the high and low natural gas resource volume scenarios used in the study.

As described in the main body of the report, remaining recoverable resource estimates are comprised of the sum of remaining reserves, reserve growth and undiscovered technically recoverable resources (UTRR). Our uncertainty analysis is designed to generate predictive probability distributions for reserve growth and UTRR. For the purposes of this study, reserve uncertainty is considered to be negligible compared to other uncertainties.[1] Reserve growth is discussed first, followed by a description of our treatment of UTRR. Reserve growth is treated simply because publicly available data is highly variable and geographically spotty. By comparison, our analysis of UTRR is more comprehensive. As described in the report, only Canadian and U.S. unconventional resources are considered because data for the rest of the world are sparse and unreliable. The last section of the appendix discusses how our uncertainty analysis is used to create "High "and "Low" cost curves.

### Reserves and Reserve Growth

The country-level ***reserves*** data are from the *Oil and Gas Journal*. As mentioned previously, reserve numbers uncertainty is treated as negligible relative to UTRR.

***Reserve growth*** probability intervals are based on reserve growth probability distributions computed by Attanasi and Coburn (Attanasi and Coburn 2004). Their reserve growth method is based on historical increases in field sizes; approximate standard deviations are found by "bootstrapping"[2] the data at 30 years of reserve growth and at 80 years of reserve growth. They use the Energy Information Administration's (EIA) U.S. oil and gas field reported reserves in the U.S. (Oil and Gas Integrated Field File (OGIFF)) as their database. This database enables the tracking of growth in Estimated Ultimate Recovery for all U.S. fields over very long periods of time. The results are summarized in Table 2B.1.

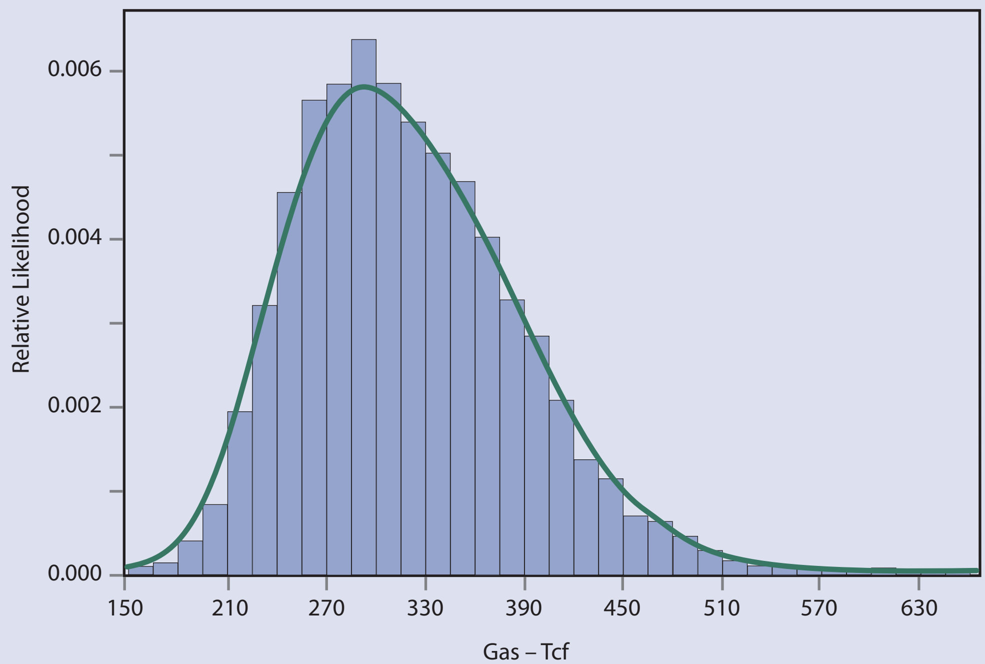
For this study, we adopt a very simple model of natural gas reserve growth uncertainty in which we consider the probability distribution computed by Attanasi and Coburn for total natural gas constructed for the 80-year time horizon.

**Table 2B.1 90% Confidence Intervals for U.S. Gas Reserve Growth for 30- and 80-Year Time Horizons. "Base" refers to the mean value of the reserve growth estimate for the given time period.**

| | Resource Type | Units | 5% | Base | 95% |
|---|---|---|---|---|---|
| 30 Years | Associated Gas | Tcf | 28.1 | 50.8 | 82.4 |
| | Non-associated Gas | Tcf | 110.4 | 138.0 | 188.4 |
| | Total Gas | Tcf | 148.4 | 188.8 | 243.2 |
| 80 Years | Associated Gas | Tcf | 40.0 | 77.5 | 137.9 |
| | Non-associated Gas | Tcf | 161.9 | 215.6 | 343.4 |
| | Total Gas | Tcf | 216.7 | 293.1 | 412.9 |

Source: Attanasi and Coburn 2004

**Figure 2B.1 Probability Distribution for Total Natural Gas Reserve Growth over an 80-Year Time Horizon**




Source: Attanasi and Coburn 2004

First the ratio of the P5 to mean reserve growth and P95 to the mean reserve growth horizon is calculated. These ratios are 0.7 and 1.4, respectively. Then the mean reserve growth volume adopted in this study is multiplied by these low and high ratios of 0.7 and 1.4 to construct the high and low cases, respectively.

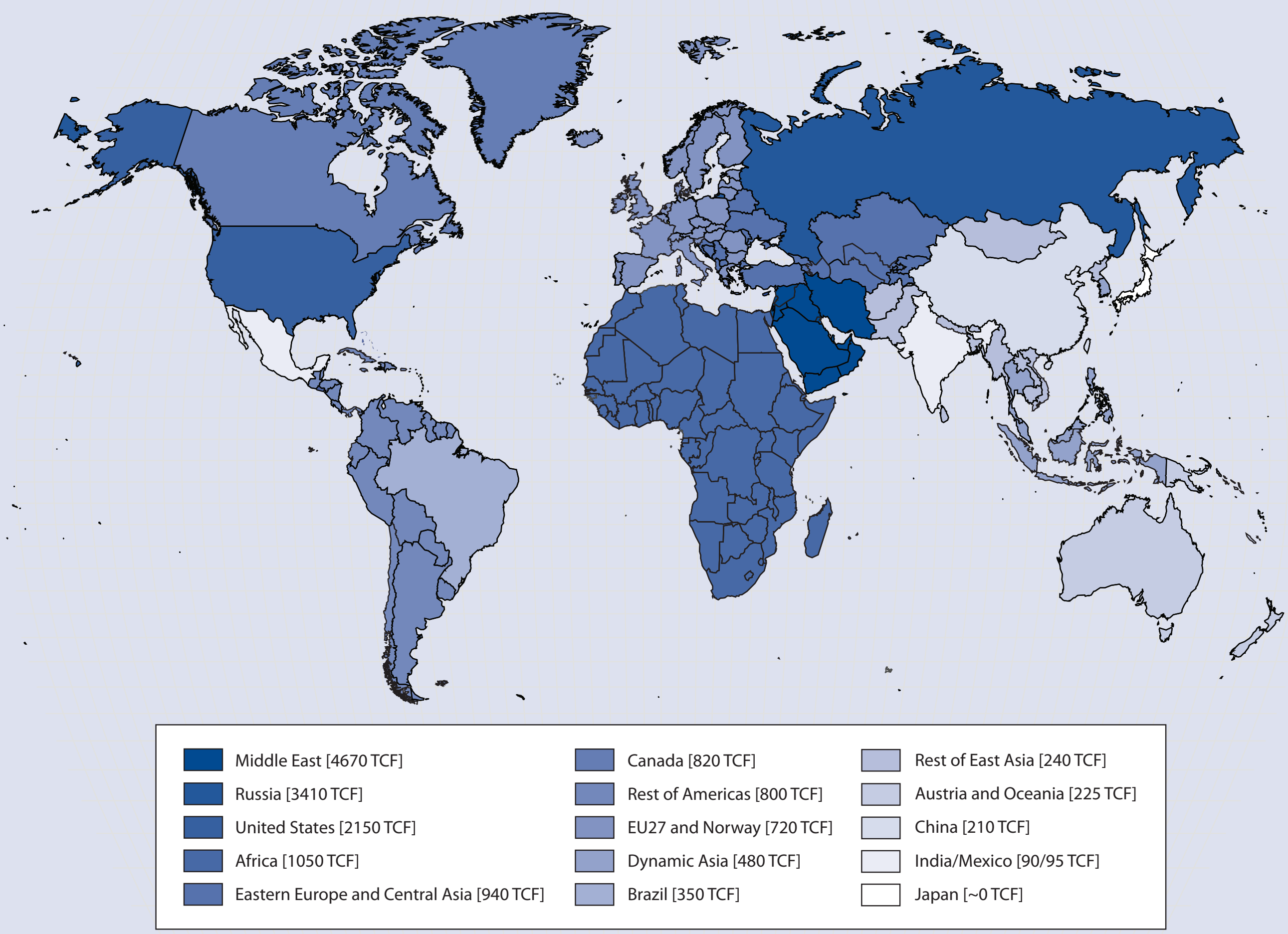
This approach is crude, but with the limited availability of historical field level data of reported reserves, a more sophisticated analysis is not possible.

## Undiscovered Technically Recoverable Resource

*Addressing the Problem of Aggregation*
For the purposes of this study — and in particular to provide supply curve input to EPPA — our objective is to create uncertainty ranges that, when aggregated over all regions, provide reasonable uncertainty intervals for the aggregate.

The issue is that if, for each of the 16 EPPA regions (see Figure 2B.2), we compute an 80% probability interval — i.e., P10 to P90 — and then, given less-than-perfect correlation between the regions, aggregate percentiles to obtain P10 and P90 percentiles for total resources in all regions, the resulting interval becomes much wider than the 10th and 90th percentiles of the distribution of total resources in all regions. For example, adding percentiles, when the correlation between regions is 0.5, leads to global 97th and 0th percentiles. This problem is typically resolved by direct Monte Carlo simulation to create a probability distribution for total resources, but this is not practical with EPPA. To compensate for bias in computation of the probability distribution for total resources, we selected a percentile interval

**Figure 2B.2 The 16 EPPA Regions**




Source: EPPA, MIT

for each EPPA region (the same interval for each region) such that, when regional percentiles are summed to create a total resource percentile, the result is a 10th to 90th percentile range for total resources.

The aggregation procedure used in the USGS 2000 World Petroleum Assessment (Ahlbrandt et al. 2005) is our template. We assume positive functional dependency *within* each EPPA region. This condition is sufficient to allow addition of percentiles. EPPA regions are not assumed to be perfectly correlated. Rather they are assumed to be positively correlated with a correlation coefficient of 0.5.

## Creating Volume Sensitivity for UTRR

Three primary data sources are used in the course of a sensitivity analysis of UTRR: USGS, MMS, and PGC databases. For the 14 EPPA regions other than the U.S. and Canada, the USGS 2000 world assessment was used for assessment unit (AU) level data. Within the U.S., we used assessment data from:

- The USGS National Oil and Gas Assessment (NOGA) for onshore and state offshore conventional resources and tight gas resources;

- The MMS for Federal offshore conventional resources; and

- The PGC for shale gas and CBM.

The U.S. unconventional volume range is used as an analogue for Canada, as data are not available.

In the rest of this section how USGS world assessment data is used is discussed first, followed by an explanation of how we use USGS NOGA data for both tight and conventional, MMS data, and lastly PGC data.

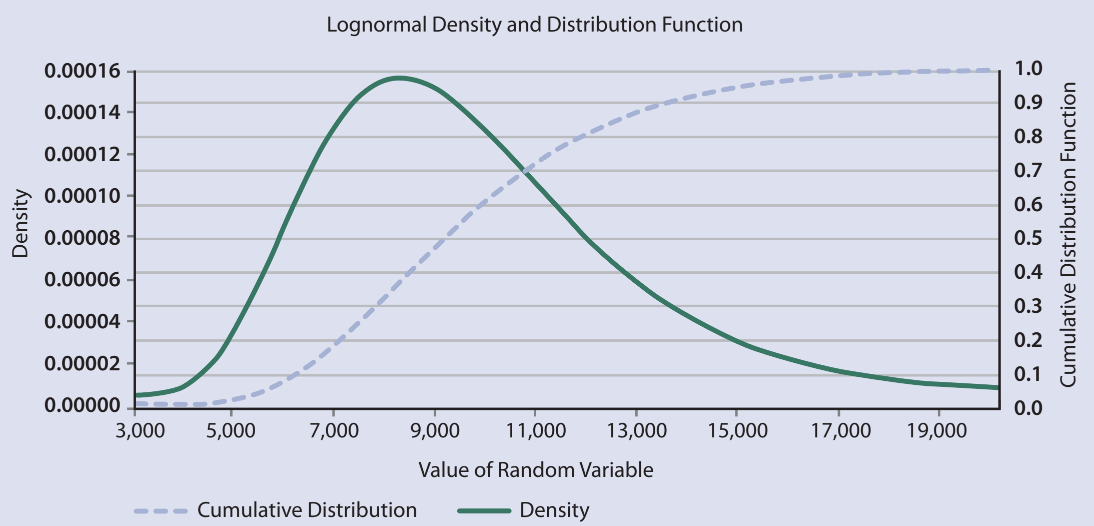
### USGS World Assessment

The USGS 2000 world assessment provides input data files for the assessment, which along with other data, contains three percentiles[3] for the size and number distributions of fields at the AU level. For associated gas, it also provides the gas-to-oil ratio percentiles. A left shifted, right truncated lognormal distribution is fit to empirical field size data. Both the number of fields in a play and the distribution of GOR distributions are fit with triangular distributions. The left shifted, right truncated lognormal distribution is:

$$f_{LN,T}(y-\gamma|\mu,\sigma)=\begin{cases}\dfrac{1}{F_{LN}(T-\gamma)\sqrt{2\pi}\sigma(y-\gamma)}\exp\left[-\dfrac{1}{2}\left(\dfrac{\ln(y-\gamma)-\mu}{\sigma}\right)^2\right], & \gamma\le y\le T,\\ 0, & \text{otherwise}\end{cases} \quad (1.1)$$

Here $T=f_{001}=F_0$ is the truncation point, $F_{LN}(T)$ is the lognormal cumulative distribution evaluated at $T$, $\gamma=f_{100}=F_{100}$ is the shift, $\mu$ and $\sigma$ are the mean and standard deviation for the normally distributed random variable $X=\ln(Y-\gamma)$. An example is shown in Figure 2B3.

**Figure 2B.3 The Density (Solid Line) and the Cumulative Distribution (Dashed Line) for the Lognormal with Parameters $\mu$ = 9, $\sigma$ = 0.35, $\gamma$ = 1,000 and $T$ = 2,000**

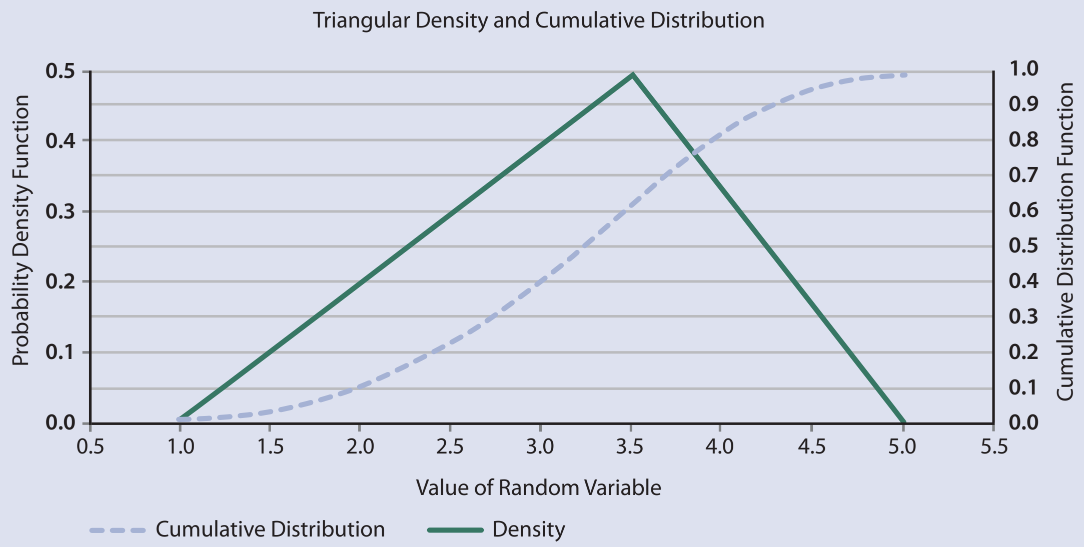


Properties of the triangular distribution are:

$$f_x(x) = \begin{cases} \dfrac{2(x-a)}{h^2 p}, & a \le x \le a+ph \\ \dfrac{2(a+h-x)}{h^2(1-p)}, & a+ph \le x \le a+h, \text{ and} \\ 0, & \text{otherwise} \end{cases} \qquad (1.2)$$

where $0 < p < 1$ is a parameter, $F_0 = a$, $F_{100} = a+h$, and the modal value is $m = a+ph$. An example is shown in Figure 2B.4.

**Figure 2B.4 An Example of the Triangular Density Function, with a Minimum of 1, a Maximum of 5 and a Modal Value of 3.5. This corresponds to *a* = 1, *h* = 4 and *p* = 0.625.**




Probability distributions for the number of fields in a play, field sizes in it and, where applicable, gas-to-oil ratios are convolved to generate risked volume distributions for associated and non-associated gas. These distributions for a given AU are then allocated to EPPA regions. Distributions of associated and non-associated gas in AUs allocated to an EPPA region are treated as mutually independent. A predictive distribution of total gas in an EPPA region is then computed by Monte Carlo simulation. If an AU lies in two different EPPA regions, it is treated as two separate AUs. Percentiles from these distributions are generated and used in the aggregation protocol.

The announced mean value of Canadian natural gas based on USGS natural gas data for Canada is small compared to mean values announced by the NPC and by the National Energy Board (NEB). Consequently, Canadian natural gas percentiles are rescaled by multiplying them by the ratio of NPC (ICF for shale) mean values to USGS mean values.

### USGS NOGA Assessment

USGS data for the U.S. onshore and state offshore are available from the NOGA program. The most recent comprehensive U.S. assessment was published in 1995. Since then, assessment of key basins has been updated. However, not all basins were updated. Where it is not, 1995 assessments are used for conventional resources.

Tight gas is assessed by fitting a three parameter lognormal distribution to 5th and 95th percentiles and means of unconventional gas. CBM and major shale plays are excluded.

### MMS Assessment

The MMS published the most recent assessment of offshore U.S. continental gas potential in 2006: percentiles and means of technically and economically recoverable volumes of associated, non-associated and, total gas in Alaskan, Pacific, Atlantic, and Gulf of Mexico (GOM) outer continental shelves (OCS). Probabilistic assessments of the number of deposits in a play and the size distribution of fields in it are held confidential. MMS percentiles of the distribution of total gas volumes for each OCS are used in our study. Additional percentiles, when needed, are computed by linear interpolation between given percentiles.

### PGC Assessment

PGC assessment data are used to construct the predictive probability intervals for U.S. shale and CBM. PGC maximum, modal, and minimum values of gas volume in each basin are used to fit a triangular distribution to gas volume.

Perfect correlation among basins is assumed and percentiles are added to arrive at an approximation to percentiles of the distribution of total U.S. CBM percentile. Shale is treated the same way. The U.S. total CBM and shale volume distribution is used as an analogue for Canada.

### Data Aggregation Procedures

Volumetric data are provided on an assessment unit or play level by the USGS and on a regional level by the MMS. The question remains how this data should be aggregated to the world level.

We chose to implement an aggregation procedure like that used by the USGS in its 2000 World Oil and Gas Assessment (T. R. Klett, D.L. Gautier, and T.S. Ahlbrandt 2000). We assume that within a given EPPA region the individual assessment unit uncertainties are correlated with positive functional dependency; that is, those factors which influence the volume of an AU up or down apply uniformly to all units within the region. Under these circumstances, the resource distribution for the region can be derived by the addition of AU percentiles.

Between EPPA regions, we assume that gas volumes in EPPA regions possess pair-wise correlations of 0.5.volumes. As the number of regions to be aggregated increases, these correlation assumptions have a significant impact on resource uncertainty distributions. Simply put, the greater the correlation between AUs, the wider the final distribution, ceteris paribus; conversely, at the global level zero correlation between individual regions leads to a much narrower distribution. In reality, it is exceptionally difficult to determine correlations between AUs in a region and correlations between regions, so following USGS assessment protocol, broad simplifying assumptions are adopted.

*Implementing Volume Sensitivity for UTRR in Cost Curve*

The previous section described the methods used to compute global and regional probability distributions for natural gas resources, which in turn can be used to compute ratios of high and low resource base scenarios to means. This section describes how these ratios are used to compute resource inputs for the cost algorithms.

Cost of supply curve uncertainty is derived from several sources: undiscovered resource volume uncertainty, uncertainty about resource development technology, and uncertainty about the time rate of discovery of natural gas.

To simplify computation, we adopt a uniform set of percentiles for all assessment units within a given EPPA region, such that when aggregated with the appropriate correlations, the resulting distribution of technically recoverable natural gas volumes correspond to the 90th and 10th percentiles of the worldwide distribution of gas. Once these volumes were determined, we scaled the number of fields in each of a finite set of size categories to correspond to the new volumes.

Partition field sizes in an AU into $K$ size classes. Let $G_i$ denote the size of a field in class $i \in \{1,\ldots,K\}$ and define $N_i$ as the number of fields of size $G_i$ in size class $i$.

Set $N = \sum_{i=1}^{K} N_i$ and $\upsilon_i = N_i / N$ .

Then total volume of conventional gas in the assessment unit is $V = N \sum_{i=1}^{K} \upsilon_i G_i$

and the mean of field sizes is $\bar{V} = \sum_{i=1}^{K} \upsilon_i G_i$ .

Our method for computation of a percentile for high and low gas resource volume scenarios is very simple: Hold both the proportion of fields in each size class $\upsilon_1,\ldots,\upsilon_K$ and class sizes $G_1,\ldots,G_K$ fixed. Suppose we declare that the $p^{th}$ percentile of the probability distribution of total gas volume in this AU is $V_{(p)}$ . Multiply each field size class count $N_i$, $i=1,\ldots K$ by $V_{(p)}/\bar{V}$ to produce a total gas volume "percentile adjusted" empirical distribution of field sizes.

There are myriad other very simple ways of creating high and low gas resource volume scenarios. For example, the resource volume distribution could be shifted up and down in a fashion that maintains the shape of the distribution. We recognize that our scaling method changes all moments of the volume distribution (variances and standard deviations in particular). Uniform scaling of the number of fields in each size class is not the only scaling option. Alternatively, we could scale size classes and keep the number of fields in each size class unchanged. Or we could have scaled both the number of fields and the sizes of each size class. However, rescaling size classes changes field size economics. Because a field's development plan depends crucially on its size, we do not do this.

For conventional resources, the mean value of field discoveries is captured by an Arps-Roberts discovery process model as a function of a given increment of exploratory wells drilled. The uncertainty in the discovery process model can be captured using successive sampling. We do not do so because it is computationally difficult to implement both the "creaming strategy" developed for the creation of supply curves and successive sampling, although both are conceptually compatible.

For unconventional UTRR, ratios are used to scale the total number of wells drilled to extract gas from each productive formation. We did not attempt to project EUR per well. To do so we would have to model UTRR technology improvements.

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## NOTES

[1]As stated above, reserve estimates are, by definition, less subject to uncertainty than are undiscovered resources. However, both the quantity and quality of available data vary widely worldwide. Reserve growth estimates for petroleum basins around the world often do not meet professional statistical quality control benchmarks.

[2]Bootstrapping is a statistical method for estimation of properties of a sampled population by "resampling" the sample itself. The probability distribution of a statistic corresponding to a property of a sampled population is computed by taking many (mutually independent) samples *with replacement* from a single observed sample: if the observed sample x is of size n, draw a sample with replacement of size n from it; repeat many times and record the empirical distribution of the statistic T(x) of interest. For moderate to large samples from the population, the resulting empirical distribution of T(x) is a reasonable approximation to the true distribution of T(x). See, for example, Efron and Gong 1983.

[3]The USGS 2000 world assessment data provided the maximum, median and minimum value for parameters used in the assessment. The NOGA program is less homogenous: post-1995 assessments provide either the median or the modal value; the 1995 assessment does not use a lognormal distribution for the size distribution and instead uses a Pareto distribution and provides the parameters needed for it.

[4]Estimates include a value for the risk in a given AU based on the probabilities for the existence of source rock, migration pathways and traps. Risk is implemented using a uniform random variable on the interval [0,1].

# Appendix 2C: Supply Curve Additional Material

Supply curves are a fundamental element of the supply study. They serve two important purposes:

(i) as primary input to the EPPA model, these curves describe the economic cost of gas resources on a regional basis, and how these costs might be expected to change as the resource base is progressively depleted;

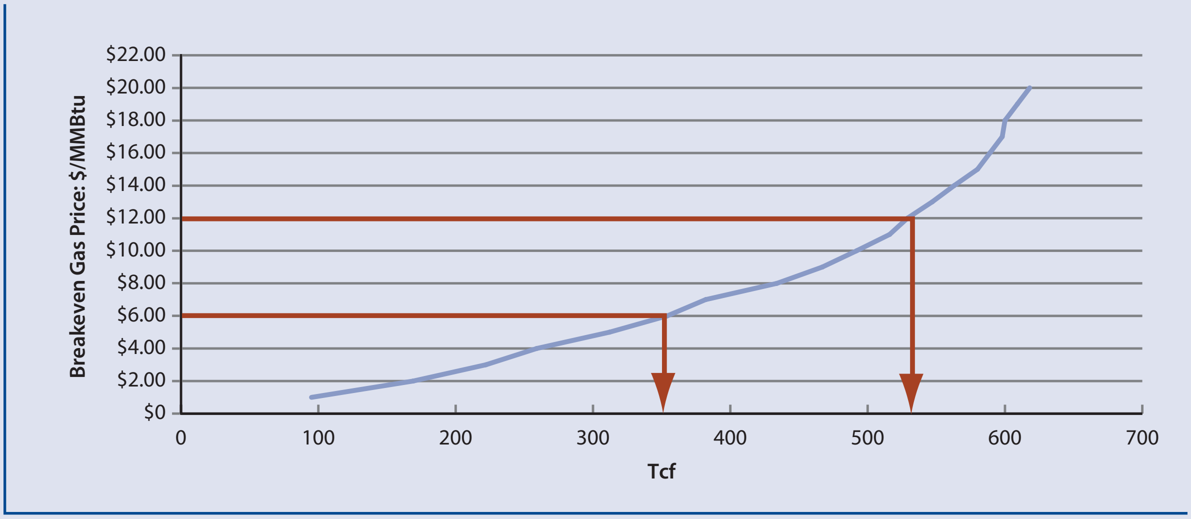
(ii) as a descriptive tool to provide a representation of the resources available in various regions and categories and, importantly, the economic cost of extracting those resources.

This appendix provides a brief overview of the methodology used in generating the supply curves used in this study, illustrates some of the key features and tabulates many of the supply curves generated. We are indebted to the consulting firm ICF, and in particular Harry Vidas and Bob Hugman, who were instrumental in using their comprehensive North American and Global natural gas supply models to construct these curves.

## DEFINITION OF SUPPLY CURVES AS USED IN THIS REPORT

A supply curve is a depiction of all the future resources that could be recovered economically at any given natural gas price level. By way of example, Figure 2C.1 shows a supply curve for Europe. At a natural gas price of \$6/MMBtu at the point of export, the chart indicates a resource potential of around 350 Tcf; at a price of \$12/MMBtu, the resource potential rises to around 520 Tcf. As will be described in more detail later, the price is that which can generate the minimum necessary rate of return to cover an investor's cost of capital.

**Figure 2C.1 Supply Curve for Europe; Gas Economic to Develop at Given Price at Point of Export; 2007 Cost Basis; Mean Case**



It is important to recognize that the supply curve is a hypothetical simplifying construct, with no time dimension. Although in resource development there is a natural propensity to move along the supply curve from large, low-cost resources to smaller, more complex, higher-cost resources over time, this progression is by no means smooth and linear. At any point in time, due to the inherent uncertainty of the exploration process, some higher-cost resources will be put into production ahead of lower-cost resources. Conversely, from time to time, as a result of technology or serendipity, lower-cost resources will emerge only after higher-cost resources have been extensively developed. This is the case, for example, with a number of emerging U.S. shale gas plays.

### Methodology for Creating Supply Curves

There are essentially three steps in the construction of a supply curve:

1. *Create an inventory of all known and potential resources within a given region.*

   This inventory will include:

   (i) currently producing fields;

   (ii) known deposits which have yet to be developed (sometimes known as stranded gas)

   (iii) development and extension of producing fields (field growth)

   (iv) estimates of the resources expected to be discovered through future exploration activity in the region (sometimes referred to as yet-to-find resources)

Resource volumes are discussed in Chapter 2 of this report, and tabulated in further detail in Appendix 2A. Table 2A.1 shows the resource estimates by EPPA region and by resource category outside North America. These resource volumes underpin the global supply curves generated for this study.

Table 2.1 in Chapter 2 provides detail on the resource estimates used as the basis for the U.S. supply curves generated for this report. In the U.S. and Canada, unconventional natural gas resources are also included in the overall resource assessments, and separate supply curves have been developed for each of the categories of tight gas, coal bed methane, and shale gas.

2. *For each category of gas, create cost and production profiles.*

In order to create supply curves, it is necessary to develop cost and production forecasts for each category of resource listed above.

For undiscovered conventional resources, modified USGS data are used to create a distribution of the number and size of all fields yet to be discovered in the region. A hypothetical program of exploration drilling is then conducted, until essentially all of the expected fields are "discovered." Through this approach, the full cost and production profile for all yet-to-be-discovered fields can be generated.

Development costs and production profiles are estimated on the basis of model algorithms that take account of field size, depth, and location. Original data sources for the cost algorithms include the API Joint Association Survey on Drilling Costs, the Petroleum Services Association of Canada Well Cost Studies, and the EIA's Oil & Gas Lease Equipment and Operating Costs, together with input obtained by ICF from private industry sources. Detailed documentation on cost assumptions for North American resource developments can be found in the National Petroleum Council report Balancing Natural Gas, September 2003.

3. *Use discounted cash-flow analysis to determine breakeven gas price.*

The cost and production profiles from Step 2 are then used, along with simplified estimates of tax and royalty, to compute the breakeven gas price for each development by discounted cash-flow analysis. The breakeven price is the gas price at which the internal rate of return for a given development is equal to an assumed hurdle rate. In this report, we have assumed a 10% hurdle rate for computing breakeven prices.

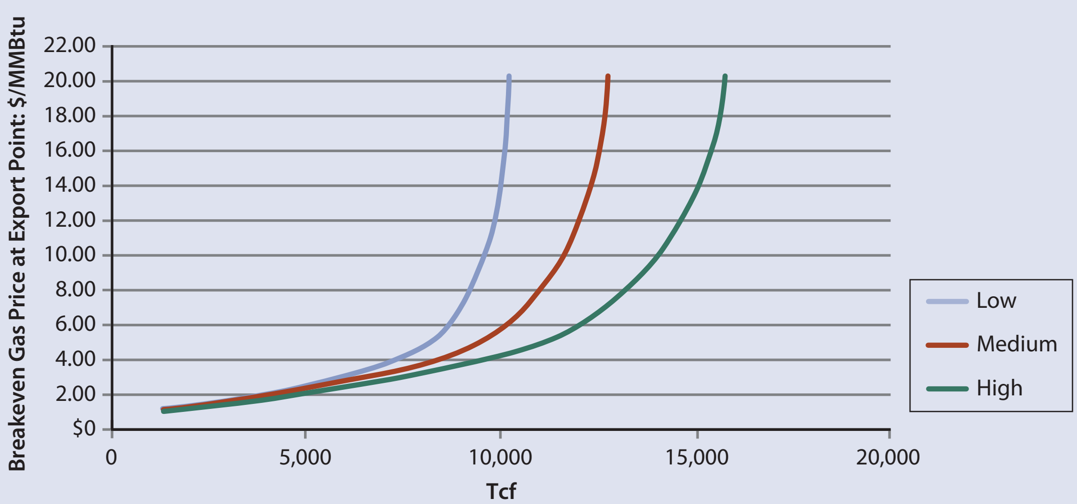
## UNCERTAINTIES AND SENSITIVITIES

### Resource Volume Uncertainty

There are many elements of uncertainty in estimating the global resource potential. A primary driver of this uncertainty lies in the estimation of undiscovered resources. The USGS database uses a statistical approach to the estimation of yet-to-find resources, which yields a probabilistic distribution of possible outcomes. There is also uncertainty in the estimation of reserve growth, and statistical methods have been employed to determine the uncertainty in this component of the total resource volumes. For the purposes of the report, proved reserves are assumed to have no uncertainty. Clearly this is an approximation, but we have effectively assumed that the uncertainty in proved reserves is minimal in comparison to the uncertainty in reserve growth and undiscovered resources.

Details of the methodology used in the estimation of volumetric uncertainty data in this report are described in detail in Appendix 2B. Figure 2C.2 demonstrates the impact of this uncertainty on the global level supply curves. The Low Case represents the supply curve for the resource estimate that has a 90% probability of being met or exceeded, and the High Case represents the curve for resource estimates that has only a 10% probability of being met or exceeded.

**Figure 2C.2 Global Gas Supply Curve, with Uncertainty; Excluding U.S. and Canada; 2007 Cost Basis**



Tables 2C.1 through 2C.6 of this appendix tabulate the cost curves for each EPPA region, excluding the U.S. and Canada, for the Low, Mean, and High resource cases, and for a 2004 and 2007 cost basis.

Figure 2C.3 illustrates similar uncertainty bounds for the U.S. supply curve.

Tables 2C.7 through 2C.12 of this appendix tabulate the cost curves for the U.S. by resource category for the Low, Mean, and High resource cases, and for a 2004 and 2007 cost basis.

### Cost Uncertainty

Cost estimation is another significant source of uncertainty in the creation of supply curves. Aside from normal variations in costs as a

**Figure 2C.3 U.S. Gas Supply Curve, with Uncertainty; 2007 Cost Basis**

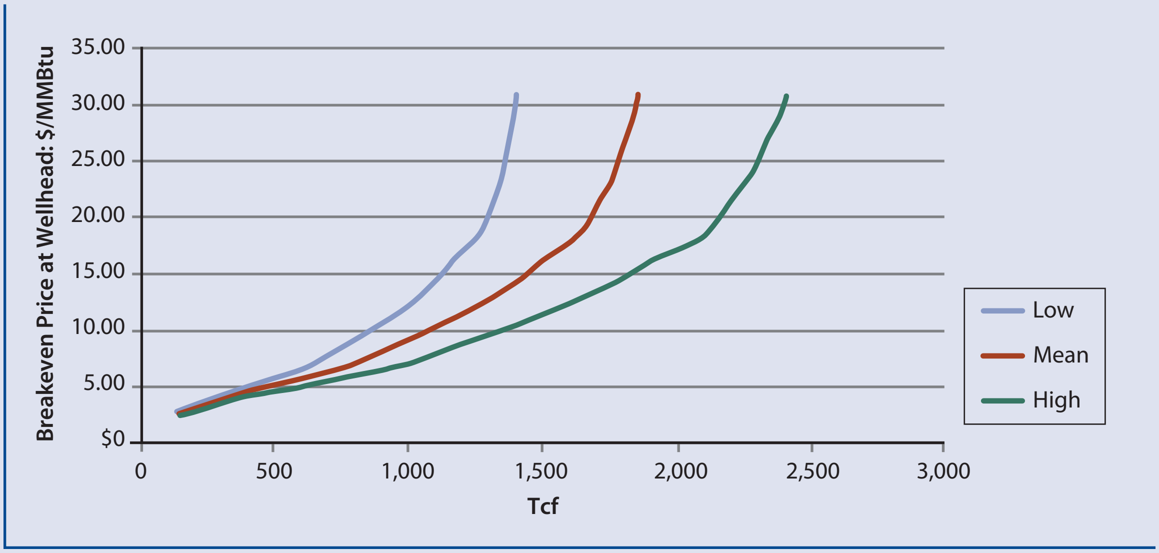
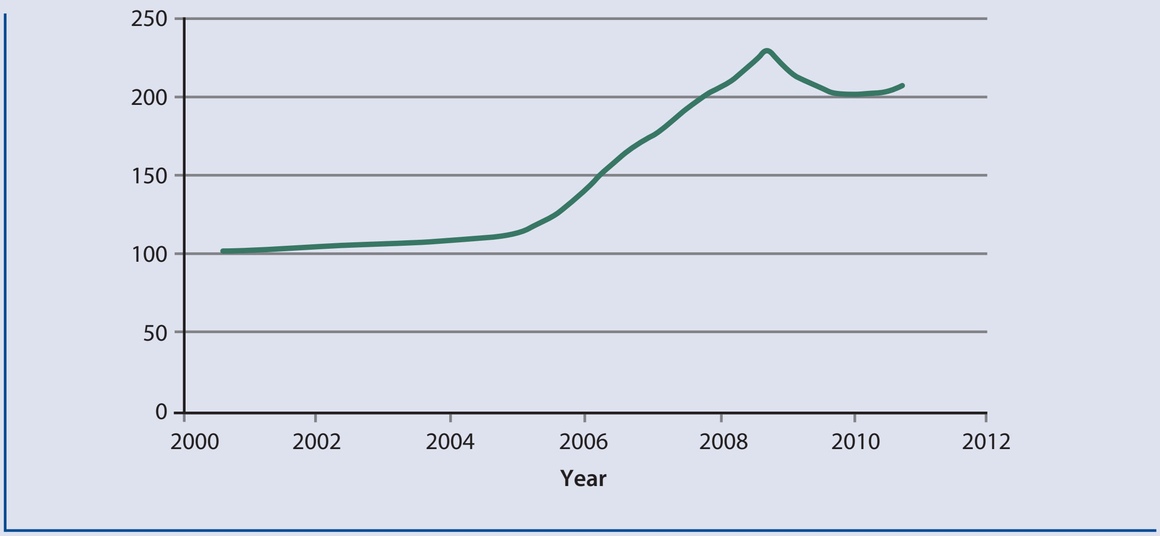



**Figure 2C.4 HIS/CERA Upstream Cost Inflation Index**



result of the heterogeneous nature of the subsurface, the major driver of cost uncertainty is oil-field cost volatility. Oil-field costs can vary dramatically over time, driven largely by activity levels in the industry. Simply put, high levels of activity drive scarcity in the provision of oil-field services, which in turn drive up costs. Since oil field activity levels are a strong function of oil price, there is a high level of correlation between oil field costs and oil price. Figure 2C.4 shows the upstream inflation index between the years 2001 and 2010. On average, the cost of performing the same activity more than doubled between 2004 and 2009, as a result of the worldwide activity level buildup over this period, before dropping off as a result of reduced activity following the economic crisis and the reduction in oil price in 2009.

**Figure 2C.5 Impact of Oil Field Cost Inflation on Supply Curves; Mean Global Resources, Excluding U.S. and Canada**

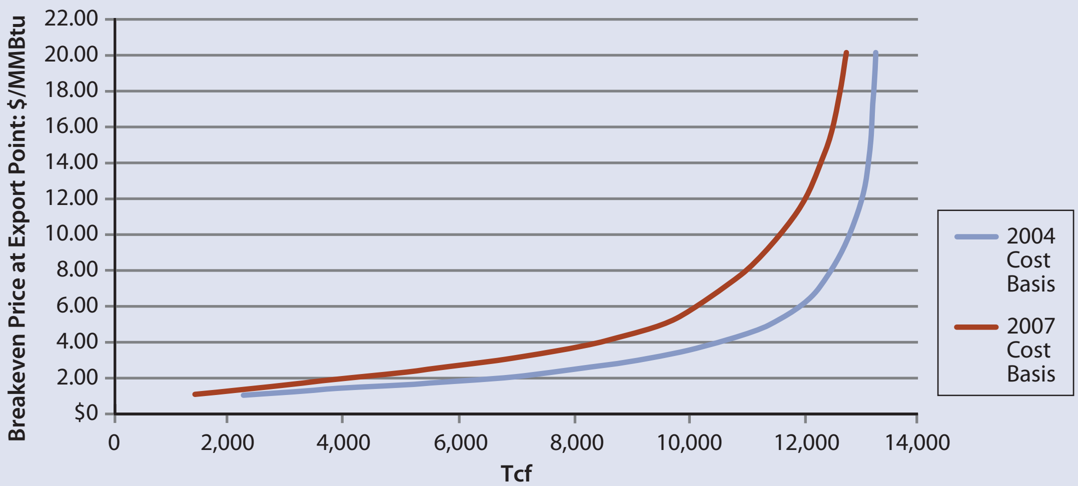
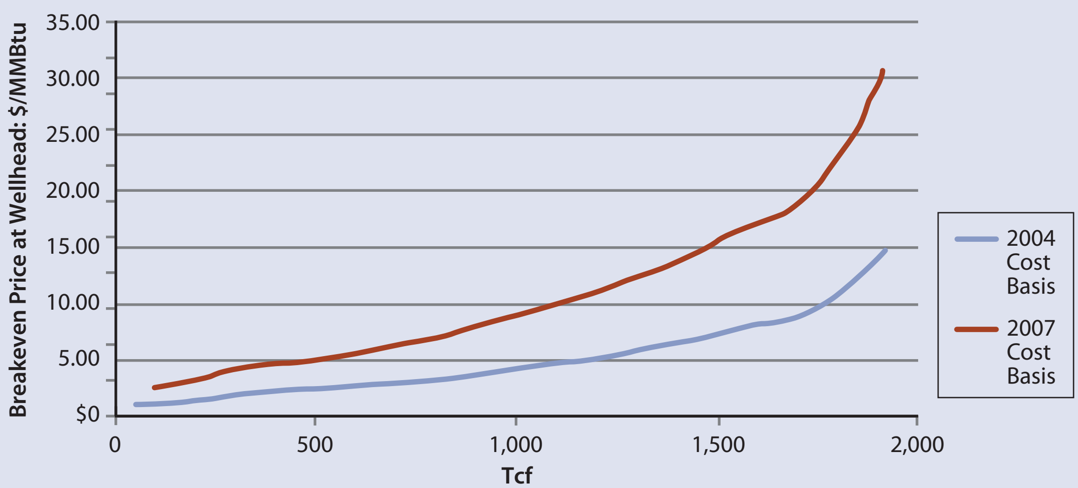



**Figure 2C.6 Impact of Oil Field Cost Inflation on Supply Curves; Mean U.S. Resources**



Given the significance of this effect, we have constructed cost curves on two distinct cost bases: 2004, which represents the last year of a relatively flat and steady period of costs; and 2007, which represents something approaching the height of the boom in oil and gas development. Clearly, the choice of base year has a substantial impact on the nature of the cost curve, as illustrated in Figures 2C.3 and 2C.4.

More detail on the impact of 2004 versus 2007 cost bases on the regional supply curves can be obtained from the supply curve Tables 2C.1 through 2C.6.

Again, more detail on the impact of 2004 versus 2007 cost bases on each category of U.S. resource can be obtained from the supply curve Tables 2C.7 through 2C.12.

### Technology Uncertainty

A further level of uncertainty is introduced through consideration of technological progress. As with most industries, the oil and gas industry benefits from technological progress over time. This progress takes several forms:

(i) learning curve effects, which allow steady progress over time. This is most readily observed in highly repetitive activities such as drilling;

(ii) quality improvements, which allow more complex and sophisticated activities to be performed over time. Drilling again provides a good example, where the developments in drilling technology have allowed for improved recoveries from complex fields;

(iii) breakthrough technologies — rare and unpredictable events that allow substantially new resources to be opened up. An excellent example is provided by the recent shale gas developments in North America.

Our base supply curves represent the application of today's technology over all future time. However, we have also attempted to model the impact of continuous technology improvement as a sensitivity case. The results for the U.S. are shown in Figure 2C.5.

**Figure 2C.7 Impact of Technology Advance on U.S. Supply Curve; Mean Resource Case; 2007 Cost Basis**

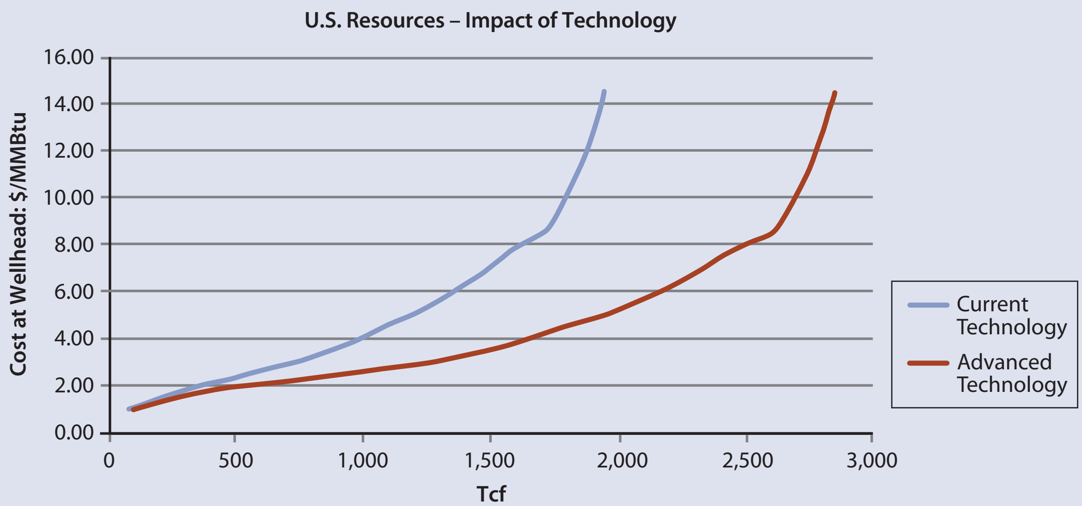


**Table 2C.1 Supply Curves by EPPA Region; Median Resource Case; 2004 Cost Base; Excludes All U.S. and Canada Resources Gas Volume Developed at Given Export Gas Price – Tcf**

| Gas Price at Export Port (2004$/MMBtu) | Africa | Australia and Oceania | Brazil | China | Dynamic Asia | Europe | India | Mexico | Middle East | Rest of Americas | Rest of East Asia | Rest of Europe and Central Asia | Russia | (All) |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| $1.00 | 165 | 19 | 27 | 35 | 83 | 96 | 19 | 12 | 1,083 | 100 | 39 | 99 | 488 | 2,266 |
| $2.00 | 396 | 37 | 47 | 51 | 165 | 171 | 41 | 19 | 3,467 | 223 | 111 | 394 | 1,868 | 6,989 |
| $3.00 | 631 | 65 | 88 | 94 | 269 | 275 | 53 | 30 | 4,044 | 346 | 161 | 536 | 2,566 | 9,159 |
| $4.00 | 746 | 113 | 138 | 129 | 342 | 378 | 65 | 41 | 4,292 | 451 | 190 | 629 | 3,029 | 10,543 |
| $5.00 | 831 | 145 | 179 | 154 | 401 | 469 | 73 | 54 | 4,419 | 521 | 209 | 706 | 3,169 | 11,330 |
| $6.00 | 890 | 165 | 211 | 169 | 425 | 528 | 78 | 64 | 4,494 | 567 | 219 | 761 | 3,242 | 11,815 |
| $7.00 | 921 | 182 | 235 | 180 | 442 | 570 | 81 | 70 | 4,543 | 602 | 225 | 801 | 3,284 | 12,135 |
| $8.00 | 946 | 193 | 254 | 186 | 451 | 595 | 82 | 76 | 4,573 | 643 | 229 | 827 | 3,321 | 12,376 |
| $9.00 | 964 | 200 | 267 | 190 | 458 | 615 | 84 | 79 | 4,594 | 679 | 232 | 846 | 3,346 | 12,552 |
| $10.00 | 975 | 205 | 278 | 195 | 465 | 632 | 85 | 81 | 4,611 | 698 | 234 | 860 | 3,363 | 12,683 |
| $11.00 | 985 | 209 | 289 | 197 | 470 | 647 | 85 | 83 | 4,625 | 717 | 236 | 872 | 3,378 | 12,793 |
| $12.00 | 993 | 212 | 297 | 199 | 473 | 659 | 86 | 85 | 4,635 | 732 | 237 | 883 | 3,390 | 12,880 |
| $13.00 | 999 | 215 | 304 | 201 | 475 | 667 | 86 | 86 | 4,643 | 744 | 238 | 891 | 3,401 | 12,951 |
| $14.00 | 1,003 | 217 | 310 | 202 | 477 | 676 | 86 | 88 | 4,650 | 748 | 239 | 898 | 3,407 | 13,001 |
| $15.00 | 1,008 | 219 | 313 | 202 | 478 | 682 | 87 | 89 | 4,653 | 751 | 240 | 903 | 3,410 | 13,035 |
| $16.00 | 1,010 | 220 | 317 | 203 | 478 | 687 | 87 | 89 | 4,654 | 760 | 240 | 907 | 3,413 | 13,064 |
| $17.00 | 1,012 | 221 | 319 | 204 | 479 | 689 | 87 | 90 | 4,656 | 762 | 240 | 909 | 3,415 | 13,083 |
| $18.00 | 1,014 | 222 | 322 | 204 | 480 | 695 | 87 | 90 | 4,657 | 768 | 240 | 913 | 3,417 | 13,110 |
| $19.00 | 1,016 | 222 | 324 | 205 | 480 | 696 | 87 | 91 | 4,658 | 770 | 240 | 916 | 3,418 | 13,123 |
| $20.00 | 1,017 | 223 | 326 | 205 | 480 | 698 | 87 | 91 | 4,659 | 772 | 240 | 917 | 3,419 | 13,134 |

**Table 2C.2 Supply Curves by EPPA Region; Low Resource Case; 2004 Cost Base; Excludes All U.S. and Canada Resources Gas Volume Developed at Given Export Gas Price – Tcf**

| Gas Price at Export Port (2004$/MMBtu) | Africa | Australia and Oceania | Brazil | China | Dynamic Asia | Europe | India | Mexico | Middle East | Rest of Americas | Rest of East Asia | Rest of Europe and Central Asia | Russia | (All) |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| $1.00 | 155 | 17 | 27 | 34 | 75 | 87 | 18 | 11 | 391 | 58 | 35 | 92 | 443 | 1,443 |
| $2.00 | 211 | 32 | 47 | 49 | 132 | 157 | 29 | 18 | 2,386 | 186 | 78 | 225 | 1,247 | 4,794 |
| $3.00 | 427 | 48 | 75 | 61 | 185 | 217 | 41 | 25 | 3,321 | 247 | 111 | 409 | 1,813 | 6,981 |
| $4.00 | 603 | 77 | 109 | 92 | 270 | 279 | 46 | 33 | 3,574 | 320 | 135 | 490 | 2,199 | 8,226 |
| $5.00 | 692 | 100 | 134 | 119 | 309 | 333 | 54 | 41 | 3,723 | 378 | 147 | 545 | 2,516 | 9,089 |
| $6.00 | 746 | 117 | 153 | 130 | 329 | 366 | 58 | 46 | 3,797 | 409 | 154 | 586 | 2,585 | 9,475 |
| $7.00 | 776 | 128 | 167 | 136 | 352 | 383 | 62 | 51 | 3,839 | 428 | 157 | 613 | 2,613 | 9,705 |
| $8.00 | 797 | 134 | 178 | 140 | 359 | 401 | 64 | 53 | 3,858 | 437 | 160 | 630 | 2,650 | 9,861 |
| $9.00 | 811 | 140 | 187 | 142 | 369 | 413 | 65 | 55 | 3,879 | 446 | 161 | 644 | 2,666 | 9,979 |
| $10.00 | 822 | 143 | 193 | 145 | 374 | 422 | 67 | 57 | 3,893 | 455 | 162 | 653 | 2,677 | 10,063 |
| $11.00 | 830 | 146 | 199 | 147 | 377 | 429 | 67 | 58 | 3,903 | 461 | 163 | 660 | 2,687 | 10,127 |
| $12.00 | 836 | 148 | 204 | 149 | 380 | 435 | 68 | 59 | 3,912 | 464 | 164 | 666 | 2,694 | 10,178 |
| $13.00 | 840 | 150 | 208 | 150 | 382 | 440 | 69 | 60 | 3,919 | 468 | 165 | 671 | 2,701 | 10,221 |
| $14.00 | 844 | 151 | 211 | 150 | 384 | 443 | 69 | 61 | 3,924 | 470 | 165 | 676 | 2,705 | 10,253 |
| $15.00 | 847 | 152 | 213 | 151 | 385 | 447 | 69 | 61 | 3,927 | 474 | 166 | 679 | 2,707 | 10,276 |
| $16.00 | 848 | 153 | 215 | 152 | 385 | 449 | 69 | 61 | 3,928 | 475 | 166 | 681 | 2,708 | 10,290 |
| $17.00 | 850 | 153 | 216 | 152 | 385 | 449 | 69 | 62 | 3,929 | 476 | 166 | 683 | 2,710 | 10,300 |
| $18.00 | 850 | 154 | 217 | 152 | 385 | 450 | 69 | 62 | 3,930 | 477 | 166 | 685 | 2,711 | 10,310 |
| $19.00 | 852 | 154 | 219 | 152 | 386 | 451 | 69 | 62 | 3,931 | 477 | 166 | 687 | 2,711 | 10,317 |
| $20.00 | 852 | 154 | 220 | 152 | 386 | 452 | 69 | 62 | 3,931 | 489 | 166 | 688 | 2,712 | 10,334 |

**Table 2C.3 Supply Curves by EPPA Region; High Resource Case; 2004 Cost Base; Excludes All U.S. and Canada Resources Gas Volume Developed at Given Export Gas Price – Tcf**

| Gas Price at Export Port (2004$/MMBtu) | Africa | Australia and Oceania | Brazil | China | Dynamic Asia | Europe | India | Mexico | Middle East | Rest of Americas | Rest of East Asia | Rest of Europe and Central Asia | Russia | (All) |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| $1.00 | 179 | 23 | 28 | 36 | 94 | 108 | 21 | 14 | 516 | 84 | 47 | 109 | 551 | 1,807 |
| $2.00 | 254 | 41 | 47 | 52 | 168 | 191 | 42 | 22 | 3,267 | 228 | 137 | 332 | 1,923 | 6,703 |
| $3.00 | 540 | 73 | 102 | 77 | 259 | 333 | 61 | 36 | 4,518 | 360 | 209 | 598 | 2,857 | 10,024 |
| $4.00 | 772 | 136 | 172 | 143 | 391 | 481 | 71 | 53 | 4,922 | 528 | 254 | 753 | 3,444 | 12,120 |
| $5.00 | 913 | 182 | 232 | 192 | 461 | 610 | 84 | 71 | 5,158 | 654 | 282 | 866 | 3,869 | 13,573 |
| $6.00 | 1,009 | 217 | 280 | 213 | 499 | 698 | 92 | 84 | 5,288 | 723 | 299 | 950 | 4,002 | 14,353 |
| $7.00 | 1,063 | 240 | 315 | 227 | 535 | 767 | 97 | 95 | 5,366 | 797 | 307 | 1,011 | 4,070 | 14,888 |
| $8.00 | 1,102 | 257 | 343 | 236 | 548 | 807 | 100 | 102 | 5,405 | 856 | 313 | 1,052 | 4,138 | 15,258 |
| $9.00 | 1,131 | 270 | 363 | 243 | 564 | 843 | 102 | 107 | 5,444 | 904 | 318 | 1,080 | 4,172 | 15,540 |
| $10.00 | 1,152 | 276 | 380 | 249 | 574 | 882 | 104 | 111 | 5,469 | 935 | 322 | 1,102 | 4,198 | 15,753 |
| $11.00 | 1,167 | 283 | 395 | 254 | 581 | 908 | 105 | 115 | 5,486 | 956 | 324 | 1,119 | 4,221 | 15,915 |
| $12.00 | 1,179 | 289 | 408 | 258 | 585 | 924 | 106 | 117 | 5,502 | 983 | 326 | 1,134 | 4,238 | 16,048 |
| $13.00 | 1,189 | 292 | 418 | 261 | 589 | 941 | 107 | 119 | 5,513 | 1,003 | 328 | 1,147 | 4,253 | 16,160 |
| $14.00 | 1,195 | 296 | 424 | 262 | 592 | 959 | 108 | 121 | 5,524 | 1,011 | 329 | 1,157 | 4,261 | 16,238 |
| $15.00 | 1,203 | 299 | 433 | 263 | 593 | 969 | 108 | 121 | 5,529 | 1,020 | 330 | 1,163 | 4,266 | 16,296 |
| $16.00 | 1,205 | 299 | 438 | 265 | 594 | 977 | 108 | 123 | 5,531 | 1,036 | 331 | 1,169 | 4,271 | 16,346 |
| $17.00 | 1,209 | 301 | 441 | 265 | 595 | 988 | 108 | 124 | 5,534 | 1,040 | 331 | 1,173 | 4,274 | 16,383 |
| $18.00 | 1,211 | 303 | 445 | 266 | 595 | 991 | 108 | 125 | 5,536 | 1,051 | 331 | 1,178 | 4,277 | 16,418 |
| $19.00 | 1,214 | 303 | 449 | 267 | 595 | 997 | 108 | 125 | 5,538 | 1,054 | 331 | 1,183 | 4,279 | 16,443 |
| $20.00 | 1,217 | 304 | 452 | 267 | 596 | 1,001 | 108 | 126 | 5,539 | 1,068 | 331 | 1,185 | 4,281 | 16,475 |

### Table 2C.4 Supply Curves by EPPA Region; Median Resource Case; 2007 Cost Base; Excludes All U.S. and Canada Resources Gas Volume Developed at Given Export Gas Price – Tcf

| Gas Price at Export Port (2007$/MMBtu) | Africa | Australia and Oceania | Brazil | China | Dynamic Asia | Europe | India | Mexico | Middle East | Rest of Americas | Rest of East Asia | Rest of Europe and Central Asia | Russia | (All) |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| $1.00 | 148 | 19 | 27 | 34 | 72 | 95 | 18 | 12 | 363 | 55 | 32 | 89 | 428 | 1,394 |
| $2.00 | 197 | 35 | 47 | 50 | 130 | 169 | 29 | 19 | 2,130 | 184 | 75 | 214 | 1,193 | 4,473 |
| $3.00 | 385 | 46 | 62 | 56 | 175 | 222 | 44 | 24 | 3,404 | 228 | 113 | 395 | 1,679 | 6,832 |
| $4.00 | 558 | 57 | 73 | 83 | 251 | 259 | 50 | 30 | 3,813 | 300 | 142 | 488 | 2,309 | 8,413 |
| $5.00 | 645 | 67 | 91 | 101 | 283 | 312 | 56 | 36 | 4,082 | 365 | 165 | 528 | 2,800 | 9,532 |
| $6.00 | 702 | 81 | 112 | 120 | 309 | 354 | 61 | 42 | 4,224 | 408 | 178 | 572 | 2,947 | 10,110 |
| $7.00 | 749 | 97 | 135 | 139 | 343 | 382 | 65 | 45 | 4,321 | 451 | 187 | 619 | 3,016 | 10,550 |
| $8.00 | 792 | 113 | 156 | 153 | 367 | 434 | 67 | 48 | 4,384 | 483 | 197 | 646 | 3,091 | 10,932 |
| $9.00 | 825 | 128 | 169 | 162 | 392 | 467 | 70 | 53 | 4,438 | 512 | 204 | 677 | 3,153 | 11,249 |
| $10.00 | 853 | 140 | 184 | 168 | 407 | 492 | 74 | 57 | 4,477 | 536 | 209 | 706 | 3,196 | 11,500 |
| $11.00 | 877 | 151 | 201 | 175 | 420 | 516 | 76 | 61 | 4,509 | 561 | 214 | 735 | 3,221 | 11,717 |
| $12.00 | 896 | 160 | 212 | 180 | 430 | 529 | 78 | 64 | 4,537 | 586 | 219 | 760 | 3,252 | 11,903 |
| $13.00 | 909 | 168 | 225 | 184 | 439 | 547 | 80 | 68 | 4,556 | 602 | 222 | 773 | 3,284 | 12,056 |
| $14.00 | 920 | 173 | 237 | 187 | 446 | 563 | 81 | 70 | 4,573 | 623 | 225 | 793 | 3,296 | 12,186 |
| $15.00 | 937 | 178 | 246 | 190 | 451 | 580 | 82 | 71 | 4,589 | 638 | 227 | 805 | 3,307 | 12,302 |
| $16.00 | 943 | 185 | 251 | 191 | 455 | 589 | 82 | 74 | 4,596 | 644 | 229 | 812 | 3,331 | 12,384 |
| $17.00 | 952 | 188 | 258 | 193 | 459 | 598 | 83 | 76 | 4,602 | 662 | 230 | 822 | 3,336 | 12,458 |
| $18.00 | 959 | 191 | 260 | 196 | 461 | 600 | 84 | 77 | 4,609 | 668 | 231 | 833 | 3,343 | 12,511 |
| $19.00 | 965 | 194 | 268 | 196 | 464 | 609 | 84 | 79 | 4,615 | 685 | 233 | 841 | 3,353 | 12,584 |
| $20.00 | 969 | 198 | 273 | 197 | 466 | 618 | 84 | 79 | 4,619 | 702 | 234 | 848 | 3,360 | 12,647 |

**Table 2C.5 Supply Curves by EPPA Region; Low Resource Case; 2007 Cost Base; Excludes All U.S. and Canada Resources Gas Volume Developed at Given Export Gas Price – Tcf**

| Gas Price at Export Port (2007$/MMBtu) | Africa | Australia and Oceania | Brazil | China | Dynamic Asia | Europe | India | Mexico | Middle East | Rest of Americas | Rest of East Asia | Rest of Europe and Central Asia | Russia | (All) |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| $1.00 | 142 | 17 | 27 | 34 | 67 | 87 | 17 | 11 | 301 | 49 | 30 | 84 | 396 | 1,262 |
| $2.00 | 186 | 31 | 47 | 49 | 120 | 155 | 26 | 18 | 1,996 | 174 | 64 | 187 | 1,062 | 4,115 |
| $3.00 | 360 | 41 | 62 | 55 | 159 | 202 | 38 | 21 | 3,033 | 212 | 88 | 353 | 1,493 | 6,117 |
| $4.00 | 514 | 50 | 74 | 76 | 227 | 235 | 43 | 26 | 3,329 | 269 | 110 | 422 | 1,955 | 7,329 |
| $5.00 | 590 | 58 | 86 | 92 | 253 | 265 | 48 | 30 | 3,532 | 316 | 125 | 450 | 2,334 | 8,178 |
| $6.00 | 638 | 69 | 99 | 103 | 271 | 291 | 51 | 34 | 3,640 | 342 | 133 | 479 | 2,431 | 8,580 |
| $7.00 | 672 | 80 | 113 | 114 | 297 | 309 | 54 | 36 | 3,710 | 364 | 138 | 509 | 2,471 | 8,867 |
| $8.00 | 703 | 90 | 125 | 122 | 312 | 336 | 56 | 38 | 3,750 | 381 | 143 | 526 | 2,521 | 9,103 |
| $9.00 | 728 | 99 | 132 | 127 | 330 | 357 | 58 | 40 | 3,789 | 397 | 147 | 544 | 2,558 | 9,307 |
| $10.00 | 748 | 106 | 142 | 131 | 339 | 372 | 60 | 43 | 3,816 | 411 | 150 | 563 | 2,583 | 9,465 |
| $11.00 | 765 | 113 | 152 | 135 | 347 | 382 | 62 | 45 | 3,836 | 422 | 153 | 581 | 2,600 | 9,593 |
| $12.00 | 778 | 118 | 158 | 139 | 354 | 391 | 64 | 48 | 3,856 | 431 | 155 | 596 | 2,618 | 9,704 |
| $13.00 | 786 | 123 | 165 | 141 | 360 | 400 | 65 | 49 | 3,868 | 438 | 157 | 604 | 2,637 | 9,794 |
| $14.00 | 793 | 125 | 172 | 143 | 365 | 406 | 65 | 51 | 3,880 | 443 | 158 | 617 | 2,644 | 9,861 |
| $15.00 | 804 | 128 | 178 | 145 | 368 | 411 | 66 | 52 | 3,890 | 451 | 160 | 623 | 2,652 | 9,928 |
| $16.00 | 808 | 133 | 179 | 145 | 370 | 416 | 66 | 53 | 3,895 | 455 | 161 | 628 | 2,664 | 9,972 |
| $17.00 | 813 | 135 | 182 | 146 | 373 | 419 | 67 | 54 | 3,898 | 457 | 161 | 633 | 2,667 | 10,004 |
| $18.00 | 817 | 137 | 184 | 148 | 374 | 420 | 67 | 54 | 3,903 | 460 | 162 | 639 | 2,671 | 10,036 |
| $19.00 | 821 | 138 | 189 | 148 | 375 | 424 | 67 | 56 | 3,906 | 462 | 162 | 644 | 2,676 | 10,068 |
| $20.00 | 823 | 139 | 192 | 149 | 377 | 426 | 68 | 56 | 3,908 | 475 | 163 | 647 | 2,680 | 10,103 |

**Table 2C.6 Supply Curves by EPPA Region; High Resource Case; 2007 Cost Base; Excludes All U.S. and Canada Resources Gas Volume Developed at Given Export Gas Price – Tcf**

| Gas Price at Export Port (2007$/MMBtu) | Africa | Australia and Oceania | Brazil | China | Dynamic Asia | Europe | India | Mexico | Middle East | Rest of Americas | Rest of East Asia | Rest of Europe and Central Asia | Russia | (All) |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| $1.00 | 157 | 22 | 27 | 35 | 80 | 107 | 19 | 13 | 414 | 63 | 35 | 96 | 474 | 1,542 |
| $2.00 | 212 | 40 | 47 | 52 | 143 | 189 | 34 | 22 | 2,304 | 198 | 91 | 222 | 1,359 | 4,912 |
| $3.00 | 406 | 54 | 62 | 59 | 197 | 250 | 51 | 27 | 3,860 | 250 | 148 | 466 | 1,912 | 7,742 |
| $4.00 | 604 | 66 | 74 | 91 | 283 | 293 | 60 | 35 | 4,388 | 340 | 183 | 570 | 2,749 | 9,736 |
| $5.00 | 711 | 78 | 99 | 113 | 323 | 372 | 68 | 44 | 4,741 | 426 | 214 | 620 | 3,365 | 11,173 |
| $6.00 | 783 | 99 | 127 | 141 | 358 | 434 | 73 | 51 | 4,930 | 489 | 237 | 681 | 3,575 | 11,979 |
| $7.00 | 841 | 123 | 160 | 169 | 402 | 474 | 78 | 56 | 5,063 | 552 | 250 | 750 | 3,678 | 12,597 |
| $8.00 | 899 | 143 | 190 | 191 | 436 | 555 | 82 | 61 | 5,150 | 603 | 263 | 790 | 3,784 | 13,148 |
| $9.00 | 944 | 163 | 208 | 203 | 469 | 605 | 86 | 68 | 5,225 | 647 | 274 | 835 | 3,879 | 13,605 |
| $10.00 | 981 | 181 | 235 | 213 | 491 | 643 | 90 | 74 | 5,279 | 685 | 283 | 877 | 3,943 | 13,974 |
| $11.00 | 1,014 | 196 | 262 | 222 | 509 | 680 | 93 | 80 | 5,324 | 724 | 291 | 918 | 3,979 | 14,292 |
| $12.00 | 1,040 | 211 | 276 | 229 | 524 | 705 | 96 | 85 | 5,363 | 762 | 297 | 954 | 4,024 | 14,565 |
| $13.00 | 1,057 | 221 | 295 | 236 | 536 | 738 | 98 | 90 | 5,389 | 789 | 302 | 972 | 4,072 | 14,796 |
| $14.00 | 1,074 | 227 | 314 | 240 | 547 | 755 | 99 | 94 | 5,413 | 826 | 306 | 1,002 | 4,092 | 14,989 |
| $15.00 | 1,100 | 236 | 327 | 245 | 553 | 775 | 101 | 96 | 5,436 | 847 | 310 | 1,019 | 4,108 | 15,152 |
| $16.00 | 1,108 | 246 | 333 | 247 | 559 | 801 | 102 | 100 | 5,447 | 856 | 313 | 1,031 | 4,144 | 15,286 |
| $17.00 | 1,120 | 251 | 346 | 249 | 566 | 815 | 103 | 103 | 5,456 | 885 | 315 | 1,045 | 4,153 | 15,406 |
| $18.00 | 1,130 | 258 | 348 | 253 | 568 | 825 | 104 | 104 | 5,465 | 897 | 317 | 1,061 | 4,162 | 15,493 |
| $19.00 | 1,138 | 261 | 362 | 254 | 572 | 848 | 104 | 107 | 5,474 | 927 | 318 | 1,073 | 4,177 | 15,616 |
| $20.00 | 1,145 | 263 | 369 | 256 | 575 | 855 | 104 | 108 | 5,479 | 947 | 320 | 1,083 | 4,189 | 15,694 |

**Table 2C.7 Supply Curves for U.S.; Mean Resource Case; 2007 Cost Index – Gas Volume Economic at Given Wellhead Price – Tcf**

| Gas Price at Wellhead (2007$/MMBtu) | Proved Reserves | Stranded Resources | Reserve Growth | Conventional New Field | Tight | Coal Bed | Shale | Misc. | Total |
|---|---|---|---|---|---|---|---|---|---|
| 2.50 | 68 | 0 | 19 | 3 | 1 | 0 | 49 | 0 | 142 |
| 3.00 | 95 | 0 | 25 | 6 | 2 | 0 | 63 | 0 | 191 |
| 3.50 | 115 | 0 | 30 | 9 | 2 | 9 | 93 | 0 | 258 |
| 4.00 | 135 | 0 | 35 | 12 | 2 | 18 | 113 | 0 | 316 |
| 4.50 | 151 | 0 | 41 | 15 | 2 | 24 | 166 | 0 | 398 |
| 5.00 | 162 | 0 | 46 | 18 | 2 | 27 | 257 | 0 | 513 |
| 5.50 | 173 | 0 | 52 | 24 | 4 | 37 | 300 | 0 | 589 |
| 6.00 | 174 | 0 | 58 | 30 | 7 | 45 | 356 | 0 | 671 |
| 7.00 | 185 | 0 | 71 | 50 | 16 | 51 | 439 | 0 | 811 |
| 8.00 | 193 | 0 | 83 | 71 | 26 | 60 | 469 | 0 | 903 |
| 9.00 | 195 | 0 | 95 | 99 | 41 | 71 | 493 | 0 | 994 |
| 10.00 | 209 | 1 | 106 | 146 | 62 | 73 | 508 | 0 | 1,105 |
| 11.00 | 217 | 1 | 117 | 185 | 67 | 76 | 523 | 0 | 1,186 |
| 12.00 | 224 | 1 | 126 | 215 | 69 | 83 | 537 | 4 | 1,259 |
| 13.00 | 231 | 1 | 135 | 245 | 84 | 86 | 552 | 4 | 1,339 |
| 14.00 | 237 | 1 | 143 | 277 | 86 | 90 | 567 | 4 | 1,405 |
| 15.00 | 237 | 1 | 150 | 301 | 94 | 91 | 582 | 4 | 1,461 |
| 16.00 | 237 | 1 | 156 | 323 | 96 | 92 | 597 | 4 | 1,506 |
| 17.00 | 237 | 8 | 161 | 349 | 113 | 95 | 612 | 4 | 1,579 |
| 18.00 | 237 | 34 | 166 | 370 | 121 | 97 | 627 | 4 | 1,655 |
| 19.00 | 237 | 34 | 169 | 389 | 122 | 98 | 631 | 4 | 1,684 |
| 20.00 | 237 | 34 | 173 | 405 | 128 | 100 | 631 | 4 | 1,712 |
| 21.00 | 237 | 34 | 176 | 417 | 129 | 101 | 631 | 4 | 1,730 |
| 22.00 | 237 | 34 | 179 | 431 | 131 | 101 | 631 | 12 | 1,756 |
| 23.00 | 237 | 34 | 181 | 446 | 133 | 101 | 631 | 12 | 1,775 |
| 24.00 | 237 | 34 | 184 | 459 | 135 | 103 | 631 | 12 | 1,795 |
| 25.00 | 237 | 34 | 186 | 471 | 137 | 104 | 631 | 12 | 1,811 |
| 26.00 | 237 | 34 | 187 | 480 | 139 | 105 | 631 | 12 | 1,826 |
| 27.00 | 237 | 34 | 189 | 489 | 141 | 107 | 631 | 12 | 1,839 |
| 28.00 | 237 | 34 | 190 | 496 | 142 | 107 | 631 | 12 | 1,850 |
| 29.00 | 237 | 34 | 192 | 504 | 144 | 108 | 631 | 12 | 1,862 |
| 30.00 | 237 | 34 | 193 | 511 | 146 | 109 | 631 | 12 | 1,874 |
| 31.00 | 237 | 34 | 194 | 518 | 148 | 110 | 631 | 12 | 1,883 |
| 70.00 | 237 | 34 | 209 | 742 | 173 | 115 | 631 | 15 | 2,156 |

**Table 2C.8 Supply Curves for U.S.; Low Resource Case; 2007 Cost Index – Gas Volume Economic at Given Wellhead Price – Tcf**

| Gas Price at Wellhead (2007$/MMBtu) | Proved Reserves | Stranded Resources | Reserve Growth | Conventional New Field | Tight | Coal Bed | Shale | Misc. | Total |
|---|---|---|---|---|---|---|---|---|---|
| 2.50 | 68 | 0 | 15 | 3 | 1 | 0 | 37 | 0 | 124 |
| 3.00 | 95 | 0 | 19 | 5 | 1 | 1 | 47 | 0 | 169 |
| 3.50 | 115 | 0 | 24 | 7 | 1 | 6 | 70 | 0 | 223 |
| 4.00 | 135 | 0 | 28 | 9 | 1 | 13 | 85 | 0 | 271 |
| 4.50 | 151 | 0 | 32 | 11 | 1 | 17 | 125 | 0 | 336 |
| 5.00 | 162 | 0 | 36 | 13 | 1 | 19 | 193 | 0 | 425 |
| 5.50 | 173 | 0 | 41 | 17 | 3 | 25 | 225 | 0 | 485 |
| 6.00 | 174 | 0 | 46 | 22 | 5 | 31 | 267 | 0 | 546 |
| 7.00 | 185 | 0 | 56 | 37 | 12 | 35 | 329 | 0 | 654 |
| 8.00 | 193 | 0 | 66 | 53 | 20 | 42 | 352 | 0 | 724 |
| 9.00 | 195 | 0 | 75 | 74 | 31 | 49 | 370 | 0 | 793 |
| 10.00 | 209 | 1 | 84 | 108 | 47 | 50 | 381 | 0 | 879 |
| 11.00 | 217 | 1 | 92 | 133 | 51 | 52 | 392 | 0 | 938 |
| 12.00 | 224 | 1 | 99 | 152 | 52 | 57 | 403 | 3 | 992 |
| 13.00 | 231 | 1 | 106 | 170 | 63 | 60 | 414 | 3 | 1,048 |
| 14.00 | 237 | 1 | 112 | 188 | 65 | 62 | 426 | 3 | 1,094 |
| 15.00 | 237 | 1 | 118 | 202 | 71 | 63 | 437 | 3 | 1,132 |
| 16.00 | 237 | 1 | 122 | 215 | 72 | 64 | 448 | 3 | 1,162 |
| 17.00 | 237 | 8 | 126 | 229 | 84 | 66 | 459 | 3 | 1,213 |
| 18.00 | 237 | 34 | 130 | 241 | 91 | 67 | 470 | 3 | 1,273 |
| 19.00 | 237 | 34 | 133 | 252 | 91 | 68 | 473 | 3 | 1,291 |
| 20.00 | 237 | 34 | 136 | 261 | 96 | 69 | 473 | 3 | 1,310 |
| 21.00 | 237 | 34 | 138 | 269 | 97 | 70 | 473 | 3 | 1,321 |
| 22.00 | 237 | 34 | 141 | 276 | 98 | 70 | 473 | 9 | 1,339 |
| 23.00 | 237 | 34 | 143 | 284 | 100 | 70 | 473 | 9 | 1,350 |
| 24.00 | 237 | 34 | 144 | 291 | 101 | 71 | 473 | 9 | 1,361 |
| 25.00 | 237 | 34 | 146 | 298 | 103 | 72 | 473 | 9 | 1,372 |
| 26.00 | 237 | 34 | 147 | 303 | 104 | 73 | 473 | 9 | 1,381 |
| 27.00 | 237 | 34 | 149 | 308 | 105 | 74 | 473 | 9 | 1,389 |
| 28.00 | 237 | 34 | 150 | 312 | 107 | 74 | 473 | 9 | 1,396 |
| 29.00 | 237 | 34 | 151 | 317 | 108 | 75 | 473 | 9 | 1,404 |
| 30.00 | 237 | 34 | 152 | 321 | 109 | 76 | 473 | 9 | 1,412 |
| 31.00 | 237 | 34 | 152 | 325 | 111 | 76 | 473 | 9 | 1,417 |
| 70.00 | 237 | 34 | 164 | 446 | 130 | 80 | 473 | 11 | 1,575 |

**Table 2C.9 Supply Curves for U.S.; High Resource Case; 2007 Cost Index – Gas Volume Economic at Given Wellhead Price – Tcf**

| Gas Price at Wellhead (2007$/MMBtu) | Proved Reserves | Stranded Resources | Reserve Growth | Conventional New Field | Tight | Coal Bed | Shale | Misc. | Total |
|---|---|---|---|---|---|---|---|---|---|
| 2.50 | 68 | 0 | 25 | 5 | 1 | 0 | 65 | 0 | 164 |
| 3.00 | 95 | 0 | 32 | 8 | 3 | 2 | 83 | 0 | 222 |
| 3.50 | 115 | 0 | 39 | 12 | 3 | 12 | 122 | 0 | 302 |
| 4.00 | 135 | 0 | 45 | 15 | 3 | 24 | 149 | 0 | 371 |
| 4.50 | 151 | 0 | 52 | 19 | 3 | 32 | 218 | 0 | 475 |
| 5.00 | 162 | 0 | 60 | 24 | 3 | 36 | 337 | 0 | 621 |
| 5.50 | 173 | 0 | 67 | 31 | 5 | 49 | 393 | 0 | 718 |
| 6.00 | 174 | 0 | 75 | 40 | 9 | 60 | 467 | 0 | 825 |
| 7.00 | 185 | 0 | 92 | 65 | 20 | 67 | 576 | 0 | 1,005 |
| 8.00 | 193 | 0 | 108 | 93 | 34 | 80 | 615 | 0 | 1,122 |
| 9.00 | 195 | 0 | 123 | 130 | 53 | 94 | 646 | 0 | 1,241 |
| 10.00 | 209 | 1 | 137 | 191 | 80 | 97 | 666 | 0 | 1,381 |
| 11.00 | 217 | 1 | 150 | 248 | 87 | 101 | 685 | 0 | 1,489 |
| 12.00 | 224 | 1 | 163 | 290 | 89 | 110 | 705 | 5 | 1,587 |
| 13.00 | 231 | 1 | 174 | 335 | 108 | 115 | 724 | 5 | 1,694 |
| 14.00 | 237 | 1 | 184 | 384 | 111 | 120 | 744 | 5 | 1,786 |
| 15.00 | 237 | 1 | 193 | 420 | 121 | 122 | 764 | 5 | 1,863 |
| 16.00 | 237 | 1 | 200 | 451 | 124 | 123 | 783 | 5 | 1,925 |
| 17.00 | 237 | 8 | 207 | 494 | 145 | 127 | 803 | 5 | 2,026 |
| 18.00 | 237 | 34 | 213 | 525 | 156 | 129 | 822 | 5 | 2,121 |
| 19.00 | 237 | 34 | 218 | 553 | 157 | 131 | 827 | 5 | 2,162 |
| 20.00 | 237 | 34 | 223 | 577 | 165 | 134 | 827 | 5 | 2,202 |
| 21.00 | 237 | 34 | 227 | 595 | 167 | 134 | 827 | 5 | 2,227 |
| 22.00 | 237 | 34 | 230 | 615 | 169 | 134 | 827 | 16 | 2,264 |
| 23.00 | 237 | 34 | 234 | 639 | 171 | 135 | 827 | 16 | 2,293 |
| 24.00 | 237 | 34 | 236 | 660 | 174 | 137 | 827 | 16 | 2,322 |
| 25.00 | 237 | 34 | 239 | 678 | 176 | 139 | 827 | 16 | 2,347 |
| 26.00 | 237 | 34 | 241 | 692 | 179 | 141 | 827 | 16 | 2,367 |
| 27.00 | 237 | 34 | 244 | 705 | 181 | 143 | 827 | 16 | 2,386 |
| 28.00 | 237 | 34 | 245 | 715 | 183 | 143 | 827 | 16 | 2,401 |
| 29.00 | 237 | 34 | 247 | 728 | 186 | 144 | 827 | 16 | 2,419 |
| 30.00 | 237 | 34 | 249 | 739 | 188 | 146 | 827 | 16 | 2,436 |
| 31.00 | 237 | 34 | 250 | 749 | 191 | 146 | 827 | 16 | 2,450 |
| 70.00 | 237 | 34 | 269 | 1,097 | 223 | 153 | 827 | 19 | 2,860 |

**Table 2C.10 Supply Curves for U.S.; Mean Resource Case; 2004 Cost Index – Gas Volume Economic at Given Wellhead Price – Tcf**

| Gas Price at Wellhead (2004$/MMBtu) | Proved Reserves | Stranded Resources | Reserve Growth | Conventional New Field | Tight | Coal Bed | Shale | Misc. | Total |
|---|---|---|---|---|---|---|---|---|---|
| 1.00 | 68 | 0 | 15 | 1 | 0 | 0 | 11 | 0 | 96 |
| 1.25 | 95 | 0 | 21 | 4 | 1 | 0 | 55 | 0 | 177 |
| 1.50 | 115 | 0 | 26 | 7 | 2 | 3 | 73 | 0 | 226 |
| 1.75 | 135 | 0 | 32 | 10 | 2 | 13 | 100 | 0 | 292 |
| 2.00 | 151 | 0 | 38 | 13 | 2 | 22 | 136 | 0 | 361 |
| 2.25 | 162 | 0 | 44 | 16 | 2 | 26 | 214 | 0 | 464 |
| 2.50 | 173 | 0 | 50 | 21 | 3 | 32 | 287 | 0 | 566 |
| 2.75 | 174 | 0 | 56 | 27 | 6 | 43 | 328 | 0 | 634 |
| 3.00 | 185 | 0 | 63 | 37 | 10 | 47 | 388 | 0 | 729 |
| 3.25 | 193 | 0 | 70 | 47 | 15 | 50 | 428 | 0 | 802 |
| 3.50 | 195 | 0 | 76 | 59 | 18 | 52 | 458 | 0 | 859 |
| 4.00 | 209 | 0 | 89 | 81 | 40 | 68 | 485 | 0 | 971 |
| 4.50 | 217 | 0 | 101 | 121 | 44 | 72 | 500 | 0 | 1,056 |
| 5.00 | 224 | 1 | 112 | 169 | 67 | 74 | 516 | 0 | 1,163 |
| 5.50 | 231 | 1 | 123 | 204 | 69 | 81 | 532 | 3 | 1,243 |
| 6.00 | 237 | 1 | 132 | 233 | 78 | 84 | 548 | 4 | 1,318 |
| 6.50 | 237 | 1 | 141 | 270 | 86 | 89 | 563 | 4 | 1,392 |
| 7.00 | 237 | 1 | 148 | 297 | 94 | 91 | 579 | 4 | 1,451 |
| 7.50 | 237 | 1 | 155 | 319 | 96 | 92 | 595 | 4 | 1,499 |
| 8.00 | 237 | 4 | 160 | 348 | 111 | 95 | 610 | 4 | 1,569 |
| 8.50 | 237 | 34 | 165 | 369 | 121 | 96 | 626 | 4 | 1,653 |
| 9.00 | 237 | 34 | 169 | 389 | 122 | 98 | 631 | 4 | 1,684 |
| 9.50 | 237 | 34 | 174 | 406 | 128 | 100 | 631 | 4 | 1,714 |
| 10.00 | 237 | 34 | 177 | 419 | 130 | 101 | 631 | 5 | 1,733 |
| 10.50 | 237 | 34 | 179 | 433 | 132 | 101 | 631 | 12 | 1,759 |
| 11.00 | 237 | 34 | 182 | 449 | 134 | 101 | 631 | 12 | 1,780 |
| 11.50 | 237 | 34 | 184 | 463 | 136 | 104 | 631 | 12 | 1,800 |
| 12.00 | 237 | 34 | 186 | 475 | 138 | 104 | 631 | 12 | 1,817 |
| 12.50 | 237 | 34 | 188 | 484 | 139 | 106 | 631 | 12 | 1,831 |
| 13.00 | 237 | 34 | 190 | 492 | 141 | 107 | 631 | 12 | 1,844 |
| 13.50 | 237 | 34 | 191 | 500 | 143 | 107 | 631 | 12 | 1,856 |
| 14.00 | 237 | 34 | 193 | 509 | 145 | 109 | 631 | 12 | 1,870 |
| 14.50 | 237 | 34 | 194 | 516 | 147 | 109 | 631 | 12 | 1,880 |
| 32.50 | 237 | 34 | 209 | 742 | 173 | 115 | 631 | 15 | 2,156 |

**Table 2C.11 Supply Curves for U.S.; Low Resource Case; 2004 Cost Index – Gas Volume Economic at Given Wellhead Price – Tcf**

| Gas Price at Wellhead (2004$/MMBtu) | Proved Reserves | Stranded Resources | Reserve Growth | Conventional New Field | Tight | Coal Bed | Shale | Misc. | Total |
|---|---|---|---|---|---|---|---|---|---|
| 1.00 | 68 | 0 | 12 | 1 | 0 | 0 | 8 | 0 | 89 |
| 1.25 | 95 | 0 | 16 | 3 | 1 | 0 | 41 | 0 | 158 |
| 1.50 | 115 | 0 | 21 | 5 | 1 | 2 | 54 | 0 | 199 |
| 1.75 | 135 | 0 | 25 | 7 | 1 | 9 | 75 | 0 | 253 |
| 2.00 | 151 | 0 | 30 | 9 | 1 | 15 | 102 | 0 | 309 |
| 2.25 | 162 | 0 | 34 | 12 | 1 | 18 | 160 | 0 | 388 |
| 2.50 | 173 | 0 | 39 | 16 | 2 | 22 | 215 | 0 | 468 |
| 2.75 | 174 | 0 | 44 | 20 | 4 | 30 | 246 | 0 | 518 |
| 3.00 | 185 | 0 | 49 | 27 | 7 | 33 | 291 | 0 | 592 |
| 3.25 | 193 | 0 | 55 | 35 | 11 | 35 | 321 | 0 | 649 |
| 3.50 | 195 | 0 | 60 | 43 | 14 | 36 | 344 | 0 | 692 |
| 4.00 | 209 | 0 | 70 | 60 | 30 | 47 | 364 | 0 | 780 |
| 4.50 | 217 | 0 | 79 | 90 | 33 | 50 | 375 | 0 | 844 |
| 5.00 | 224 | 1 | 88 | 123 | 50 | 51 | 387 | 0 | 925 |
| 5.50 | 231 | 1 | 96 | 145 | 51 | 56 | 399 | 2 | 982 |
| 6.00 | 237 | 1 | 104 | 164 | 59 | 59 | 411 | 3 | 1,037 |
| 6.50 | 237 | 1 | 111 | 184 | 65 | 62 | 423 | 3 | 1,085 |
| 7.00 | 237 | 1 | 117 | 200 | 70 | 63 | 434 | 3 | 1,125 |
| 7.50 | 237 | 1 | 122 | 213 | 72 | 64 | 446 | 3 | 1,158 |
| 8.00 | 237 | 4 | 126 | 228 | 83 | 66 | 458 | 3 | 1,205 |
| 8.50 | 237 | 34 | 130 | 240 | 91 | 67 | 470 | 3 | 1,271 |
| 9.00 | 237 | 34 | 133 | 252 | 91 | 68 | 473 | 3 | 1,292 |
| 9.50 | 237 | 34 | 136 | 262 | 96 | 70 | 473 | 3 | 1,311 |
| 10.00 | 237 | 34 | 139 | 270 | 97 | 70 | 473 | 4 | 1,324 |
| 10.50 | 237 | 34 | 141 | 278 | 99 | 70 | 473 | 9 | 1,341 |
| 11.00 | 237 | 34 | 143 | 286 | 100 | 70 | 473 | 9 | 1,353 |
| 11.50 | 237 | 34 | 145 | 293 | 102 | 72 | 473 | 9 | 1,365 |
| 12.00 | 237 | 34 | 146 | 300 | 103 | 72 | 473 | 9 | 1,375 |
| 12.50 | 237 | 34 | 148 | 305 | 104 | 74 | 473 | 9 | 1,384 |
| 13.00 | 237 | 34 | 149 | 310 | 106 | 74 | 473 | 9 | 1,393 |
| 13.50 | 237 | 34 | 150 | 315 | 107 | 74 | 473 | 9 | 1,400 |
| 14.00 | 237 | 34 | 152 | 320 | 109 | 76 | 473 | 9 | 1,410 |
| 14.50 | 237 | 34 | 152 | 324 | 110 | 76 | 473 | 9 | 1,416 |
| 32.50 | 237 | 34 | 164 | 446 | 130 | 80 | 473 | 11 | 1,575 |

## Table 2C.12 Supply Curves for U.S.; High Resource Case; 2004 Cost Index – Gas Volume Economic at Given Wellhead Price – Tcf

| Gas Price at Wellhead (2004$/MMBtu) | Proved Reserves | Stranded Resources | Reserve Growth | Conventional New Field | Tight | Coal Bed | Shale | Misc. | Total |
|---|---|---|---|---|---|---|---|---|---|
| 1.00 | 68 | 0 | 20 | 2 | 0 | 0 | 14 | 0 | 104 |
| 1.25 | 95 | 0 | 27 | 6 | 2 | 1 | 73 | 0 | 203 |
| 1.50 | 115 | 0 | 34 | 9 | 3 | 4 | 95 | 0 | 260 |
| 1.75 | 135 | 0 | 41 | 13 | 3 | 17 | 131 | 0 | 340 |
| 2.00 | 151 | 0 | 48 | 17 | 3 | 29 | 178 | 0 | 426 |
| 2.25 | 162 | 0 | 56 | 21 | 3 | 34 | 280 | 0 | 557 |
| 2.50 | 173 | 0 | 64 | 28 | 4 | 43 | 376 | 0 | 688 |
| 2.75 | 174 | 0 | 72 | 36 | 7 | 57 | 430 | 0 | 776 |
| 3.00 | 185 | 0 | 81 | 48 | 13 | 63 | 508 | 0 | 897 |
| 3.25 | 193 | 0 | 90 | 62 | 19 | 67 | 562 | 0 | 991 |
| 3.50 | 195 | 0 | 98 | 77 | 24 | 69 | 601 | 0 | 1,064 |
| 4.00 | 209 | 0 | 114 | 106 | 51 | 91 | 636 | 0 | 1,207 |
| 4.50 | 217 | 0 | 130 | 159 | 57 | 96 | 656 | 0 | 1,315 |
| 5.00 | 224 | 1 | 145 | 224 | 87 | 99 | 677 | 0 | 1,456 |
| 5.50 | 231 | 1 | 158 | 275 | 88 | 108 | 698 | 4 | 1,562 |
| 6.00 | 237 | 1 | 171 | 317 | 101 | 113 | 718 | 5 | 1,662 |
| 6.50 | 237 | 1 | 181 | 373 | 111 | 119 | 739 | 5 | 1,767 |
| 7.00 | 237 | 1 | 191 | 413 | 121 | 121 | 759 | 5 | 1,849 |
| 7.50 | 237 | 1 | 199 | 446 | 124 | 122 | 780 | 5 | 1,916 |
| 8.00 | 237 | 4 | 206 | 491 | 142 | 127 | 801 | 5 | 2,014 |
| 8.50 | 237 | 34 | 213 | 524 | 156 | 129 | 821 | 5 | 2,119 |
| 9.00 | 237 | 34 | 218 | 553 | 157 | 131 | 827 | 5 | 2,163 |
| 9.50 | 237 | 34 | 224 | 578 | 165 | 134 | 827 | 5 | 2,204 |
| 10.00 | 237 | 34 | 227 | 598 | 167 | 134 | 827 | 7 | 2,232 |
| 10.50 | 237 | 34 | 231 | 620 | 170 | 134 | 827 | 16 | 2,269 |
| 11.00 | 237 | 34 | 234 | 645 | 172 | 135 | 827 | 16 | 2,301 |
| 11.50 | 237 | 34 | 237 | 666 | 175 | 138 | 827 | 16 | 2,330 |
| 12.00 | 237 | 34 | 240 | 684 | 177 | 139 | 827 | 16 | 2,354 |
| 12.50 | 237 | 34 | 242 | 698 | 180 | 142 | 827 | 16 | 2,375 |
| 13.00 | 237 | 34 | 244 | 709 | 182 | 143 | 827 | 16 | 2,393 |
| 13.50 | 237 | 34 | 246 | 722 | 185 | 143 | 827 | 16 | 2,410 |
| 14.00 | 237 | 34 | 248 | 734 | 187 | 146 | 827 | 16 | 2,430 |
| 14.50 | 237 | 34 | 250 | 745 | 190 | 146 | 827 | 16 | 2,445 |
| 32.50 | 237 | 34 | 269 | 1,097 | 223 | 153 | 827 | 19 | 2,860 |

# Appendix 2D: Shale Gas Economic Sensitivities

This appendix provides an economic analysis of the breakeven gas prices for the major U.S. shale plays; that is, the wellhead gas price at which the natural gas producer can achieve a 10% internal rate of return (IRR) for a given well performance. In keeping with the theme of uncertainty, this analysis explores the considerable variability of economic performance, both within and between various shale plays. This analysis is supplementary to the broad-brush description of shale gas breakeven prices described in the natural gas supply curves.

### Background

A discounted cash flow (DCF) model has been used to carry out all of the breakeven price calculations shown in this report. This model calculates the wellhead gas price which generates a 10% IRR, using a full-cycle per-well approach. The revenue in the model is generated from the well's production, while the costs include: leasing of acreage; drilling and completion; operation and maintenance; and payment of royalties and taxes, all on an individual well basis. The uncertainty around well production rates has been captured by statistical analysis of the actual performance of shale wells completed in 2009. The uncertainty around drilling, completion, and operational costs is captured through the definition of a set of cost sensitivities (high, mid, and low) for each play. These sensitivities have been designed to reasonably reflect the variation in each of the parameters that has been observed in practice. The model uses two royalty rates, 12.5% and 25%, a severance tax rate of 5%, and Federal and state corporate tax rates of 35% and 5%, respectively (yielding a marginal corporate tax rate of 38.3%). The model assumes all lease and capital expenditures occur in year 0, and that production begins in year 0+6 months. Drilling and completion costs are written down according to U.S. fiscal rules, while lease costs are written down using percentage cost depletion, with the total well resource being calculated assuming a 60-year well life.

The sensitivities used for the drilling and completion costs in each of the plays are shown in Table 2D.1 (a). The high, mid, and low estimates of lease costs, and operation and maintenance costs are shown in Table 2D.1 (b). All values have been chosen in an effort to reflect the typical range in costs that have been reported for each play; however, we acknowledge that individual instances of higher or lower costs are certain to have occurred. Furthermore, we recognize that the rapid evolution of drilling performance with experience will affect these estimates over time.

**Table 2D.1a High, Mid, and Low Estimates of Well Drilling and Completion Cost in the Five Major Shale Plays**

| $ Million | Low | Mid | High |
|---|---|---|---|
| Barnett | 3.0 | 3.5 | 4.0 |
| Fayetteville | 3.0 | 3.5 | 4.0 |
| Haynesville | 6.5 | 7.5 | 8.5 |
| Marcellus | 3.5 | 4.0 | 4.5 |
| Woodford | 4.5 | 5.0 | 5.5 |

**Table 2D.1b High, Mid, and Low Estimates for Lease Costs ($/Acre) and Operating and Maintenance Cost ($/MMBtu) for All Five Major Shale Plays**

| | Low | Mid | High |
|---|---|---|---|
| Lease $/acre | 2,500 | 5,000 | 10,000 |
| Opex $/MMBtu | 0.5 | 0.75 | 1.0 |

### Average Breakeven Prices

The 2009 30-day average initial production (IP) rate, the estimated average EUR and the breakeven gas prices for each of the major shale plays, assuming no co-liquid production, are shown in Table 2D.2. The breakeven prices were calculated using the mid case cost scenario shown in Table 2D.1 and assuming a 12.5% royalty rate.

The breakeven price range of $4.00 to 6.00/MMBtu indicates some variation in average economic performance between the major shale plays. However, these differences in average performance are relatively small when compared to the variations of economic performance within individual shale plays, driven by substantial variations in initial production rate.

### Economic Sensitivity to Initial Production Rate

To illustrate this, we have created a distribution of IPs for all wells completed in 2009, for the five major shale plays. As an example, Figure 2D.1 depicts the probability density distribution of initial production rates for all wells completed in the Barnett shale in 2009.

The P20 30-day IP rate represents the rate that is equaled or exceeded by only 20% of the wells completed in 2009; the P80 represents the initial rate equaled or exceeded by 80% of completed wells. The spread in performance is wide, and this leads to a very wide distribution of breakeven prices (BEP) across each of the shales, as depicted in Table 2D.3.

**Table 2D.2 Full-Cycle Breakeven Prices for Each of the Major U.S. Shale Plays Assuming Mid Case Costs and Average IP Rates for Wells Drilled in 2009**

| | Barnett | Fayetteville | Haynesville | Marcellus | Woodford |
|---|---|---|---|---|---|
| IP rate – 2009 30-day average (Mcf/day) | 1,840 | 2,090 | 7,880 | 3,500 | 2,530 |
| EUR (Bcf) | 2.8 | 3.2 | 5.5 | 5.4 | 3.9 |
| Breakeven price ($/MMBtu) | 5.84 | 5.25 | 5.04 | 4.00 | 5.96 |

**Figure 2D.1 Probability Density Distribution of the 30-Day Average IP Rate for Wells Completed in the Barnett Shale during 2009**

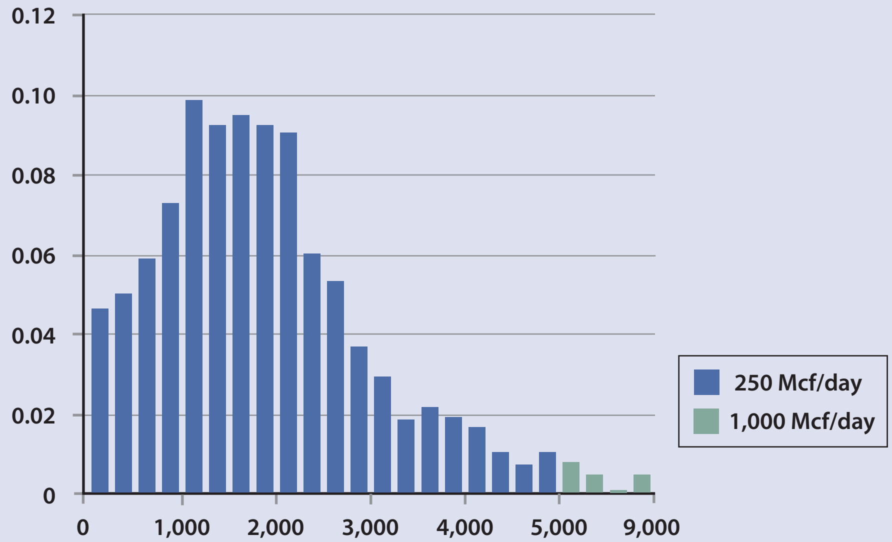



**Table 2D.3 Full-Cycle 2009 Well Vintage P20, P50, and P80 30-Day Average IP Rates and Breakeven Prices for Each of the Major U.S. Shale Plays Assuming Mid Case Costs**

| | Barnett | | Fayetteville | | Haynesville | | Marcellus | | Woodford | |
|---|---|---|---|---|---|---|---|---|---|---|
| | IP Mcf/d | BEP $/Mcf | IP Mcf/d | BEP $/Mcf | IP Mcf/d | BEP $/Mcf | IP Mcf/d | BEP $/Mcf | IP Mcf/d | BEP $/Mcf |
| P20 | 2,700 | $4.27 | 3,090 | $3.85 | 12,630 | $3.49 | 5,500 | $2.88 | 3,920 | $4.12 |
| P50 | 1,610 | $6.53 | 1,960 | $5.53 | 7,730 | $5.12 | 3,500 | $4.02 | 2,340 | $6.34 |
| P80 | 860 | $11.46 | 1,140 | $8.87 | 2,600 | $13.42 | 2,000 | $6.31 | 790 | $17.04 |

Even though on average some plays have lower BEPs than others, it is the individual quality of wells that will determine whether a play is attractive or not to an operator. In most instances, individual operators will have many wells in a play, some better than average, others worse, with the relative weighting of good to bad wells determining its overall quality.

### Economic Sensitivity to Costs and Royalty

Lease rates and the capital costs involved in drilling and completing wells can vary significantly depending upon the stage of development of a play, its relative quality, the price of gas, the availability of labor and equipment, etc., which all have an impact on the BEP of a well. To illustrate this, the BEPs of average 2009 Barnett and Haynesville wells (assuming no co-liquid production) were calculated using royalty rates of 0%, 12.5% and 25%, along with the differing capital, operating, and lease costs defined in Table 2D.1. The impact these changes have on the breakeven prices of average wells in those plays are shown in Figure 2D.2 (a) and (b).

These results indicate that well economics are less sensitive to variations in costs and royalties than to IP rates. Nevertheless, the sensitivities are significant. The breakeven price is most sensitive to the royalty rate, and the capital cost associated with drilling and completion also has a large impact. Economic outcomes are much less sensitive to the lease and operating costs.

**Figure 2D.2a Impact of Variations in Royalties and Other Costs on the Breakeven Price of a Mean Performance 2009 Barnett Well**

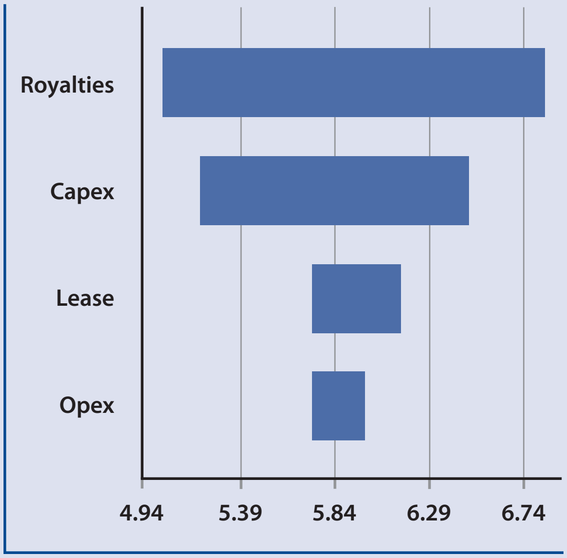
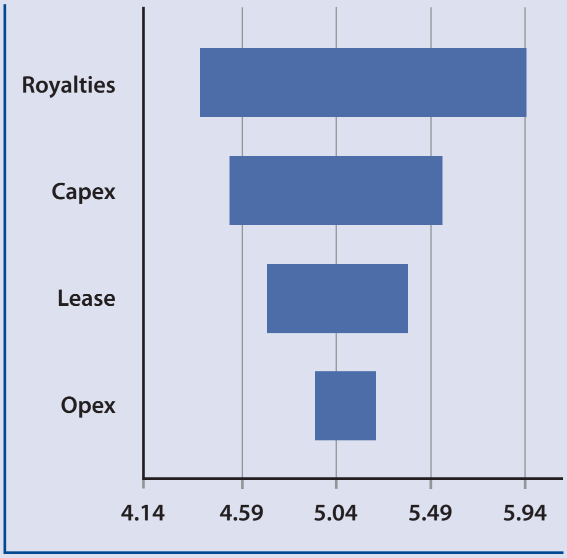



**Figure 2D.2b Impact of Variations in Royalties and Other Costs on the Breakeven Price of a Mean Performance 2009 Haynesville Well**



### Economic Sensitivity to Liquid Co-production

The other major driver of shale economics is the amount of hydrocarbon liquid produced along with natural gas. The analysis so far has assumed "dry" gas with no liquid co-production; however, some areas contain "wet" gas with appreciable amounts of liquid. The price of the liquids is linked to oil and so even if the BEP of a well is high on a natural gas-only basis, if the well is "wet" and producing appreciable amounts of liquids, it may have a much lower effective breakeven gas price — particularly if the price of oil is high compared to the price of natural gas. The liquid content of a gas is often measured in terms of the "condensate ratio," expressed in terms of barrels of liquid per million cubic feet of gas (bbls/MMcf).

It is illustrative to explore how varying levels of "wetness" can impact the breakeven economics of a typical play. Figure 2D.4 shows the change in breakeven gas price for varying condensate ratios in a typical Marcellus well[1], assuming a liquids price of \$80/bbl. It can be seen that for a condensate ratio in excess of approximately 50 bbls/MMcf in this particular case, the liquid production alone can provide an adequate return on the investment, even if the natural gas were to realize no market value.

The effects described above create an interesting dynamic in U.S. gas supply. Gas prices have been driven to low levels in 2009 and 2010, at least in part as a result of the abundance of relatively low-cost shale gas. Meanwhile oil prices, determined by global market forces, have remained high. This has led producers to seek liquid-rich natural gas plays, such as

**Figure 2D.3 Estimated Breakeven Gas Price (\$/MMBtu) for a Mean Performing 2009 Vintage Marcellus Shale Well, with Varying Condensate Ratio (bbl/MMcf), Assuming a Liquids Price of \$80/bbl**

certain areas of the Marcellus or the Eagle Ford play in Texas, where condensate ratios can be well in excess of 100 bbl/MMcf. These plays then enable more natural gas production, even at low gas prices, thus putting further downward pressure on these prices.

### Future Trends in Shale Gas Economics

Predicting the future economics of shale gas is difficult for many reasons, principal among those being the fact that shale gas production, at least in the contemporary sense, is still very much in its infancy, despite the current contribution it makes to overall U.S. production. Up until recently, the only shale play with significant output was the Barnett. Clearly this is changing rapidly; however, the Barnett still contains 75% of all the modern shale wells.

Using the development of the Barnett as a template for what might take place in the newer shale plays seems reasonable. In the Barnett, there has been a continuous improvement in the performance of wells year-on-year. This is due to a combination of improved geological knowledge and operational methods. The results of these advances have undoubtedly helped improve the relative economics of the play. However, these improvements are taking place while the resource base is being developed, and the best acreage is typically drilled first. This results in a general downgrading of the resource left to be developed, which offsets the positive impact of the operational improvements. Resource downgrading is already in evidence in the Barnett. Therefore, even with very significant technical and operational advances, the rate of increase in well performance has slowed, particularly between 2008 and 2010 and it is likely that this trend will continue going forward as much of the best acreage in the Barnett's core has already been drilled.

In contrast to the relatively mature Barnett, the Haynesville and particularly the Marcellus shales are still at the beginning of their developments. Both plays present very different geological and operational challenges than those faced in the Barnett. It is reasonable to expect that as operators gain experience, progress on addressing these challenges will be made, with the result that there may still be opportunity to appreciably improve the relative economics of these plays.

## NOTES

[1]These are illustrative calculations only, not based on actual "wet" well performance. The calculations assume that well performance, costs, etc., are unchanged by increasing levels of liquids production. In practice, well gas production may be affected by liquid co-production.

# Appendix 2E: Overview and Analysis of Publicly Reported Incidents Related to Gas Well Drilling

In order to provide some perspective on the relative frequency and type of incidents over the past several years that appear to have some connection with gas well drilling, we have summarized the results of three reports from differing sources that examine this issue, and categorized the reported incidents according to type.

It is beyond the scope of this report to undertake a detailed analysis of all state-reported incidents — and we do not claim this to be a definitive analysis of all known incidents. Rather, it is intended to give a general picture of the types of incidents that occur and their relative frequency. It should also be noted that, for many incidents, it can be difficult to establish cause and effect, so there is a significant measure of uncertainty inherent within this analysis.

The reports reviewed were as follows:

1. Frac Attack: Risk, Hype, and Financial Reality of Hydraulic Fracturing in the Shale Plays; July 8, 2010; A Special Report by Reservoir Research Partners and Tudor Pickering & Holt

   This report reviews a selective list of publicized incidents; it is not intended to be exhaustive; and the focus is on recent incidents.

2. Fractured Communities — Case Studies of the Environmental Impacts of Industrial Gas Drilling; September 2010; Craig Michaels, Program Director; James L. Simpson, Senior Attorney; William Wegner, Staff Scientist; Watershed

   "The studies in this report rely exclusively on investigations, findings and statements of state and Federal regulators in the Marcellus Shale regions (Pennsylvania, Ohio and West Virginia), the Barnett Shale (Texas), the Fayetteville Shale (Louisiana and Arkansas), as well as regulators in the western states of Wyoming and Colorado."

3. Hydraulic Fracturing: Preliminary Analysis of Recently Reported Contamination; September 2009; Prepared for: Drinking Water Protection Division (DWPD) Office of Ground Water and Drinking Water (OGWDW) U.S. Environmental Protection Agency (EPA); Prepared by The Cadmus Group Inc.

   This report reviews publicly available information on reported incidents of drinking water contamination, apparently caused by or related to gas well drilling operations. The report is based on "information obtained from internet searches and anecdotal information provided to the Agency by outside sources." The focus is on incidents reported from 2004 onwards (the publication year of a previous EPA report on hydraulic fracturing.

Table 2E.1 summarizes the results of this high-level review. Of the 43 incidents reviewed, almost 50% were related to the contamination of groundwater with natural gas, as the result of drilling operations. Most frequently, this appears to be related to inadequate cementing of casing into wellbores, allowing natural gas to migrate from lower formations into groundwater zones. Properly implemented cementing procedures should prevent this from occurring. The second major category is on-site surface spills, which can arise from a variety of causes — from hose leaks to overflowing pits to breaching of pit linings.

It is noteworthy that no incidents of direct invasion of shallow water zones by fracture fluids during the fracturing process have been recorded. Nevertheless, these incidents clearly demonstrate that there have been real issues with the integrity of natural gas drilling operations in the U.S. The number of incidents should be placed in the context of the many thousands of natural gas wells drilled in the U.S. over the period under review — nevertheless, some small proportion of drilling operations is clearly creating significant environmental impact, and in some cases, risk to public health and safety. Improved performance is a necessary prerequisite to improved public acceptance of natural gas development.

Table 2E.2 below provides additional detail on individual incidents, based on the three reports described above.

**Table 2E.1 Relative Frequency of Reported Incidents Associated with Natural Gas Drilling Operations**

| Type of incident | Number reported | Fraction of Total |
|---|---|---|
| Groundwater contamination by natural gas | 20 | 47% |
| On-site surface spills | 14 | 33% |
| Off-site disposal issues | 4 | 9% |
| Water withdrawal issues | 2 | 4% |
| Air quality | 1 | 2% |
| Blowouts | 2 | 4% |

**Table 2E.2 Summary of Incidents Associated with Natural Gas Drilling Operations**

| # | Where | State | When | Company | Cat | Main Issue Reported | Damage | Result | Source |
|---|---|---|---|---|---|---|---|---|---|
| 1 | Dimock | PA | 2009 | Cabot Oil & Gas | 1 | Water well explosion. Suspected poor well construction allowing migration of naturally occurring shallow gas. Gas released was found not to be shale gas. | Water contamination, explosion | Cabot provided water, plugged three wells, barred from drilling new wells in Dimock for a year | 1,2,3 |
| 2 | Dimock | PA | 2009 | Cabot Oil & Gas | 2 | Spill of lubricant gel used in fracture fluid at the drilling site due to failed pipe connections | Contaminated wetland, caused fish kill | Cabot fined $56,650, review of engineering/safety improvements. Settlement of violations led to corrective actions, providing potable water, assessed $120,000 penalty. Failure to comply led to additional $240,000 fine plus $30,000/month until full compliance achieved. | 1,2,3 |
| 3 | Bainbridge | OH | 2007 | Ohio Valley Energy Systems Corp | 1 | Explosion in a house due to natural gas leaking into aquifer caused by high-pressure gas in annulus of surface production casing | Significant damage to house, water contamination in the area | Gas flow stopped, helped evacuate and house displaced residents | 1,2,3 |
| 4 | Caddo Parish | LA | 2010 | EXCO Resources | 1 | During drilling, unexpected layer of shallow gas was struck that escaped into the air. A poor cement job from an adjacent well suspected to be cause of unexpected gas pocket. | Over 100 homes temporarily evacuated | EXCO plugged 2 wells, water testing, lessons incorporated into new well designs | 1 |
| 5 | Clearfield County | PA | 2010 | EOG Resources / CC Forbes | 6 | Blowout of well during flowback period caused by equipment failure and untrained operators not using proper procedures | 35,000 gallons of wastewater and natural gas collected for 16-hour period; possibly 1 million gallons released overall, 2 creeks polluted | EOG/CC Forbes fined $400,000, EOG drilling and fracking suspended statewide, 16 violations | 1,2 |

**Table 2E.2 Summary of Incidents Associated with Natural Gas Drilling Operations** (continued)

| # | Where | State | When | Company | Cat | Main Issue Reported | Damage | Result | Source |
|---|---|---|---|---|---|---|---|---|---|
| 6 | Garfield County | CO | 2001 | Encana | 1 | Reported contamination of drinking water. Poor cement job cited for loss of containment, but no fracture fluids found in contaminated water. | Contamination of drinking water | Encana fined $266,000, settled with those hurt | 1,2,3 |
| 7 | Pavillion | WY | 2000+ | Encana | 2 | Complaints about contaminated drinking water over prolonged period | Further studies ongoing | No clear linkage established between drilling activities and contamination | 1,2,3 |
| 8 | Caddo Parish | LA | 2009 | Chesapeake Energy | 2 | State regulators concluded that fluid leaked from site into pasture | Cattle found dead, not conclusively connected to leakage | Chesapeake and Schlumberger fined $22,000 each | 1 |
| 9 | Dunkard Creek | PA | 2009 | Unclear | 3 | Algae growth in river allegedly caused by high salinity from fracture flowback fluids | Fish kill along 43-mile stretch of creek caused by spread of invasive algae | Report found coal-mine discharges to be potential contributing source. No linkage to gas drilling or fracturing established. | 1 |
| 10 | Lower Monongahela River | PA | 2008 | Unclear | 3 | Ability of wastewater treatment plants to safely process fracture flowback fluids called into question | High levels of total dissolved solids, and high salinity in river | More stringent standards, plants ordered to reduce fracture wastewater processing from 20% max to 1% of daily flow | 1,2 |
| 11 | Hopewell Township | PA | 2009 | Range Resources | 2 | Broken transmission line led to spill of 7,750 barrels of diluted fracture fluids | Contaminated stream, killing over 100 fish in area rich in biodiversity | Range Resources fined $141,175 | 1,2 |
| 12 | Bradford County | PA | 2010 | Chesapeake Energy | 1 | Methane found in drinking wells | Water contamination | Ordered to provide water to affected families while further investigated | 2 |
| 13 | North Central | PA | 2008 | Various | 4 | Water taken from rivers without permits | | Susquehana River Basin Authority notified companies about permits required, and stopped operations using unpermitted water | 1 |

**Table 2E.2 Summary of Incidents Associated with Natural Gas Drilling Operations** (continued)

| # | Where | State | When | Company | Cat | Main Issue Reported | Damage | Result | Source |
|---|---|---|---|---|---|---|---|---|---|
| 14 | Dish | TX | 2009 | Various | 5 | Suspected high levels of toxic air emissions from compressor stations | | Texas Dept of Health Services found air quality to be within acceptable limits, with residents' exposure not greater than U.S. population as a whole | 1,2 |
| 15 | Marshall County | WV | 2010 | Chief Oil & Gas / AB Resources PA | 6 | Explosion of shallow gas at the surface from abandoned mine shaft; Department of Environmental Protection cited improper procedures and casing depths | 7 workers injured | Ceased operations and cited for improper casing, company had to review procedures and plans, order lifted July 2010 | 2 |
| 16 | Foster | PA | 2009 | Shreiner Oil & Gas | 1 | High methane, iron, manganese in drinking water, excessive pressure found in the surface casing | Water contamination | Order to improve cement casings, create permanent solution for affected homes | 2 |
| 17 | Bradford County | PA | 2010 | Talisman Energy | 2 | Pump failure and sand collection in valve led to spill of 4,200 gallons of flowback fluid | Fluid flowed into wetlands and streams | Fined $15,506 | 2 |
| 18 | Three Counties in SW PA | PA | 2010 | Atlas Resources | 2 | At 13 well sites, failure to implement proper control measures led to discharges of fuel and flowback fluid | Ground contamination | Fined $85,000 | 2 |
| 19 | Hopewell Township | PA | 2010 | Atlas Resources | 2 | Wastewater pit overflow of fracture fluids | Contaminated stream | Fined $97,350 | 2 |
| 20 | Troy | PA | 2010 | Fortuna Energy | 3 | Illegal discharge of flowback fluids into drainage ditch | Contaminated stream | Fined $3,500 | 2 |
| 21 | Buckeye Creek | WV | 2009 | Tapo Energy | 2 | Accidental discharge of petroleum-based material into tributary | Contaminated stream | Fined $10,000 | 2 |
| 22 | Jersey Shore | PA | 2008 | Wastewater Treatment Plant | 3 | Wastewater with high levels of chloride illegally processed by municipal treatment facility | | Ordered to stop | 2 |
| 23 | Jefferson County | PA | 2004 | Unclear | 1 | House exploded due to reported pressurization of annulus on at least 1 gas well | 3 fatalities | | 2 |

**Table 2E.2 Summary of Incidents Associated with Natural Gas Drilling Operations** (continued)

| # | Where | State | When | Company | Cat | Main Issue Reported | Damage | Result | Source |
|---|---|---|---|---|---|---|---|---|---|
| 24 | McNett Township | PA | 2009 | East Resources | 1 | Natural gas leaked from well; suspected to be caused by improper casing | 2 streams and several water wells contaminated | Some improvements seen from remedial actions at suspected wells | 2 |
| 25 | Armstrong County | PA | 2007 | Unknown | 1 | Pressurization of annulus led to explosion at water well | Damaged well pump and enclosure | | 2 |
| 26 | Knox Township | PA | 2009 | Unknown | 1 | Natural gas found in drinking wells | | | 2 |
| 27 | Millcreek Township | PA | 2007 | Unknown | 1 | Fugitive gas found in soil and houses at explosive levels | Residents evacuated for 2 months | First Alliance Church fined $32,000 for allowing drilling on their property | 2 |
| 28 | Liberty Township | PA | 2008 | Unknown | 1 | Overpressured wells led to gas migration in shallow water zones | Water well contamination | Gas wells repaired and water wells degassed | 2 |
| 29 | Washington County | PA | 2006 | Unknown | 1 | Drilling released gas from abandoned well into water supplies | Water well contamination | | 2 |
| 30 | Howe Township | PA | 2005 | Unknown | 1 | Gas migration into water supplies may be linked to nearby drilling | Water well contamination | | 2 |
| 31 | Hamlin Township | PA | 2007 | Unknown | 1 | Overpressured well led to gas migration | Water well contamination | Additional production casing in suspected well. Responsible party ordered to plug orphan wells adjacent to affected water wells. | 2,3 |
| 32 | Armstrong County | PA | 2007 | Unknown | 1 | Pressurization of surface casing led to gas migration | Explosion inside a house and contaminated water well | | 2 |
| 33 | Armstrong County | PA | 2008 | Unknown | 1 | Overpressured well | Evacuation of residence | Corrective action taken | 2 |
| 34 | Bradford County | PA | 2005 | Columbia Natural Resources | 2 | Failed to implement erosion and sedimentary controls along roadway | Contamination of streams | Fined $6,500 | 2 |

**Table 2E.2 Summary of Incidents Associated with Natural Gas Drilling Operations** (continued)

| # | Where | State | When | Company | Cat | Main Issue Reported | Damage | Result | Source |
|---|---|---|---|---|---|---|---|---|---|
| 35 | Jefferson County | PA | 2008 | Unknown | 1 | Overpressured wells led to gas migration | Filled basement of house nearby | | 2 |
| 36 | Parachute Creek | CO | 2008 | Marathon | 2 | Breach in storage pit liner led to leak of 1.4 million gallons of fracture fluid | Contamination of Parachute Creek | | 2 |
| 37 | Garfield County | CO | 2008 | Williams Production | 2 | Leaking waste pit | Contaminated spring | Agreed to pay $423,000 to resolve state investigation | 2 |
| 38 | Garfield County | CO | 2006 | Bill Barrett Corporation | 2 | Poor waste handling practices, overfilling pits, transporting without a permit | Residents complained of fumes making it uncomfortable to be outside | 9 Notices of Alleged Violations | 3 |
| 39 | North Central | AR | 2009 | XTO Energy / Southwestern Energy | 1 | Several reports of groundwater contamination | Change in water quality and quantity | Further monitoring to occur | 3 |
| 40 | Durango | CO | 2008 | Weatherford International | 2 | 130-gallon spill of ZetaFlow fracture fluid caused hospitalization of worker and illness of medical attendee | No additional damage reported | Spill too small to report, additional investigation sought. BP suspended use of ZetaFlow. | 3 |
| 41 | Huerfano County | CO | 2007 | Petroglyph | 1 | Explosion in well pump house, methane found at combustible levels coming out of water well | Explosion inside a house and contaminated water well | Petroglyph provided drinking water, monitors | 3 |
| 42 | La Plata County | CO | 2005 | Maralex Resources | 2 | Fluids leaked from unlined pit infiltrated groundwater | Contaminated wells | Maralex provided water and treatment system, fluids removed and pit backfilled | 3 |
| 43 | Lycoming County | PA | 2008 | Range Resources | 4 | Failure to obtain proper permits for withdrawing water from local stream | | Ordered to stop surface water withdrawals | 2 |

# Appendix 3A: Levelized Cost of Electricity and Competition between Natural Gas and CCS

This appendix provides the details for calculating levelized cost of electricity (LCOE) and an illustrative calculation of a required carbon price to make carbon capture and storage (CCS) technology competitive. LCOE is the cost per kilowatt-hour (kWh) that over the life of the plant fully recovers operating, fuel, capital and financial costs. Figures in the table are at point of generation and transmission, and additional distribution cost is $0.02/kWh for all technologies except wind with backup for which the cost is $0.03/kWh. The cost numbers and heat rate for the Nth plant are taken from the U.S. DOE Energy Information Administration (EIA)[1], with a correction for the way the EPPA model represents wind and solar[2]. Estimates of CCS transmission and storage cost (line 24) are taken from Hamilton (2009)[3].

## Table 3A.1 Details of Levelized Cost of Electricity (2005 cents/kWh)

| | Units | Pulverized Coal | NGCC | NGCC with CCS | IGCC with CCS | Advanced Nuclear | Wind | Biomass | Solar Thermal | Solar PV | Wind Plus Biomass Backup [a] | Wind Plus Gas Backup [a] |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| [1] "Overnight" Capital Cost | $/kW | 2049 | 892 | 1781 | 3481 | 3521 | 1812 | 3548 | 4731 | 5688 | 5360 | 2705 |
| [2] Total Capital Requirement | $/kW | 2377 | 964 | 1995 | 4177 | 4930 | 1957 | 4116 | 5109 | 6144 | 5789 | 2921 |
| [3] Capital Recovery Charge Rate | % | 10.6% | 10.6% | 10.6% | 10.6% | 10.6% | 10.6% | 10.6% | 10.6% | 10.6% | 10.6% | 10.6% |
| [4] Fixed O&M | $/kW | 25.9 | 11.0 | 18.8 | 43.5 | 84.8 | 28.6 | 60.7 | 53.5 | 11.0 | 89.2 | 39.6 |
| [5] Variable O&M | $/kWh | 0.0043 | 0.0019 | 0.0028 | 0.0042 | 0.0005 | 0.0000 | 0.0063 | 0.0000 | 0.0000 | 0.0063 | 0.0019 |
| [6] Project Life | years | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 |
| [7] Capacity Factor | % | 85% | 85% | 80% | 80% | 85% | 35% | 80% | 35% | 26% | 42% | 42% |
| [8] (Capacity Factor Wind) | | | | | | | | | | | 35% | 35% |
| [9] (Capacity Factor Biomass/NGCC) | | | | | | | | | | | 7% | 7% |
| [10] Operating Hours | hours | 7446 | 7446 | 7008 | 7008 | 7446 | 3066 | 7008 | 3066 | 2277.6 | 3679.2 | 3679.2 |
| [11] Capital Recovery Required | $/kWh | 0.03 | 0.01 | 0.03 | 0.06 | 0.07 | 0.07 | 0.0621 | 0.1761 | 0.2850 | 0.1663 | 0.0839 |
| [12] Fixed O&M Recovery Required | $/kWh | 0.003 | 0.001 | 0.00 | 0.0062 | 0.01 | 0.01 | 0.01 | 0.02 | 0.00 | 0.02 | 0.01 |
| [13] Heat Rate | Btu/kWh | 8740 | 6333 | 7493 | 8307 | 10488 | 0 | 7765 | 0 | 0 | 7765 | 6333 |
| [14] Fuel Cost | $/MMBtu | 1.40 | 6.08 | 6.08 | 1.40 | 0.63 | 0.00 | 1.03 | 0.00 | 0.00 | 1.03 | 6.08 |
| [15] (Fraction Biomass/NGCC) | % | | | | | | | | | | 8.8% | 8.2% |
| [16] Fuel Cost per kWh | $/kWh | 0.0122 | 0.0385 | 0.0456 | 0.0116 | 0.0066 | 0.0000 | 0.0080 | 0.0000 | 0.0000 | 0.0007 | 0.0032 |
| **[17] Levelized Cost of Electricity** | **$/kWh** | **0.054** | **0.056** | **0.085** | **0.092** | **0.088** | **0.077** | **0.085** | **0.194** | **0.290** | **0.198** | **0.100** |
| **[18] Markup Over Coal** | | **1.00** | **1.03** | **1.57** | **1.71** | **1.64** | **1.43** | **1.58** | **3.60** | **5.39** | **3.67** | **1.85** |

**For CCS**

| | Units | Pulverized Coal | NGCC | NGCC with CCS | IGCC with CCS |
|---|---|---|---|---|---|
| [19] Amount Fossil Fuel | EJ/KWh | 9.221E-12 | 6.68E-12 | 7.905E-12 | 8.76E-12 |
| [20] Carbon Content | MtC/EJ | 24.686 | 13.700 | 13.700 | 24.686 |
| [21] Carbon Emissions | MtC/KWh | 2.276E-10 | 9.153E-11 | 1.083E-10 | 2.163E-10 |
| [22] $CO_2$ Emissions | $tCO_2$/KWh | 0.0008 | 0.0003 | 0.0004 | 0.0008 |
| [23] $CO_2$ Emissions after 90% Capture | $tCO_2$/KWh | | | 3.971E-05 | 7.93E-05 |
| [24] Cost of $CO_2$ T&S | $/$tCO_2$ | | | 10 | 10 |
| [25] $CO_2$ Transportation & Storage Cost | $/KWh | | | 0.0036 | 0.0071 |

[a] A combined wind and biomass plant (or wind and natural gas plant) assumes that there is 1 KW installed capacity of biomass (or natural gas) for every 1 KW installed capacity of wind, and assumes the wind plant has a capacity factor of 35% and the biomass (or natural gas) plant has a capacity factor of 7%, operating only as needed to eliminate the variability of the wind resource.

[1] Input, from EIA 2010

[2] [1]+([1]*0.4*y) where y=construction time in years: coal=4, NGCC=2, IGCC with CCS=5, NGCC with CCS=3, nuclear=5, wind=2, biomass=4, solar=2, wind with biomass=2, wind with NGCC=2. For nuclear there is additional cost of ([1]*0.2) for the decommission cost.

[3] =r/(1-(1+r)^(-[6])) where r is discount rate. The discount rate is 8.5%.

[4] Input, from EIA 2010

[5] Input, from EIA 2010

[6] Input, assumption

[7] Input, standard assumptions

[8] Input, assumption

[9] Input, assumption

[10] =8760*[7] (8760 is the number of hours in a year)

[11] =([2]*[3])/[10]

[12] =[4]/[10]

[13] Input, from EIA 2010

[14] Input, from EIA data, 5-year average price from 2002-2006

[15] =[9]/80% for wind plus biomass; =[9]/85% for wind plus NGCC

[16] =[13]*[14]/1000000; for wind with backup =([13]*[14]/1000000)*[15]

[17] =[5]+[11]+[12]+[16]; for CCS technologies this also includes $CO_2$ T&S costs from [25]

[18] =[17]/([17] for coal)

[19] =[13]*(1.055*10^-15)

[20] Input, from EPPA model

[21] =[19]*[20]

[22] =[21]*(44/12)*1000000

[23] =[22]*(1-0.9), assuming 90% capture

[24] Input, from Hamilton (2009)

[25] =([22]-[23])*[24]

Table 3A.1 can also be used for calculating a carbon price that is required to make CCS technology competitive. The resulting price is driven by a relative difference in LCOE and carbon emissions. Current designs for a CCS technology envision 90% carbon capture, leaving 10% of $CO_2$ emitted. Based on information provided in Table 3A.1, a difference between LCOE for pulverized coal and coal with CCS is 0.038$/kWh. Considering the coal carbon content of 24.686 MtC/EJ, a pulverized coal technology emits 0.835kg $CO_2$ per kWh (shown in row 22), while coal with CCS emits 0.079 kg $CO_2$ per kWh (shown in row 23). Therefore, it costs 0.038$/kWh to avoid 0.755kg $CO_2$ per kWh. Converting this last result to a cost per ton of $CO_2$ leads to a required carbon price of 50.79$/t$CO_2$ to make coal with CCS competitive with pulverized coal technology.

Applying the fuel prices in Table 3A.1 (line 14) the required carbon price increases if CCS has to compete with natural gas-based electricity instead of coal-based electricity. In this case, NGCC emissions are 0.3356 kg $CO_2$ per kWh, while gas with CCS emits 0.0397 kg $CO_2$ per kWh. Considering the difference in LCOE for these technologies of 0.037$/kWh, a carbon price of 98.40$/t$CO_2$ is required to make natural gas with CCS economic when it competes with NGCC technology. A similar calculation results in a carbon price of $142.77$/t$CO_2$ that is required when coal with CCS competes with NGCC. These simple calculations illustrate that a higher carbon price is needed to justify CCS when electricity is based on natural gas in comparison to a coal-based electricity. Figure 3A.1 shows LCOE for coal and natural gas technologies with and without CCS for different carbon prices.

**Figure 3A.1 Levelized Cost of Electricity at Different Carbon Prices**

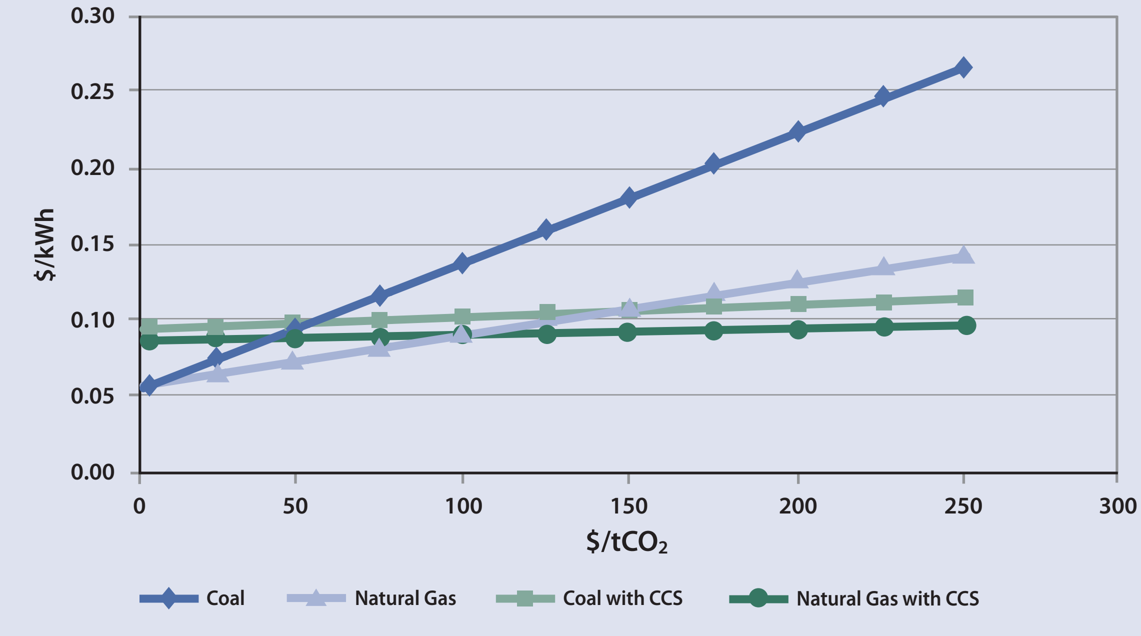



**Figure 3A.2 Least-Cost Generation Technology Zones for Coal and Natural Gas with and without CCS for Different Natural Gas Prices and Carbon Prices**

| Gas Price $/MMBtu | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| 12 | coal | coal | coal | coal_CCS | coal_CCS | coal_CCS | coal_CCS | coal_CCS | coal_CCS |
| 10 | coal | coal | coal | coal_CCS | coal_CCS | coal_CCS | coal_CCS | coal_CCS | coal_CCS |
| 8 | coal | coal | gas | gas | coal_CCS | coal_CCS | coal_CCS | gas_CCS | gas_CCS |
| 6 | coal | gas | gas | gas | gas_CCS | gas_CCS | gas_CCS | gas_CCS | gas_CCS |
| 4 | gas | gas | gas | gas | gas_CCS | gas_CCS | gas_CCS | gas_CCS | gas_CCS |
| 2 | gas | gas | gas | gas | gas_CCS | gas_CCS | gas_CCS | gas_CCS | gas_CCS |
| | 0 | 25 | 50 | 75 | 100 | 125 | 150 | 175 | 200 |

Carbon Price $/tCO_2$

Estimates of the heat rates for CCS technologies have a wide range. For example, assuming the heat rates from Hamilton (2009) instead of EIA (2010), the required carbon prices are 63.48$/t$CO_2$ a coal with CCS vs. coal competition and 196.80$/t$CO_2$ for a coal with CCS vs. natural gas competition.

Similar recalculations of the required carbon prices can be done for alternative fuel prices. Figure 3A.2 shows the zones of the least cost generation for coal and natural gas with and without CCS for a range of different natural gas and carbon prices and assuming the coal price fixed at the level shown in Table 3A.1 (line 14). Based on the costs of coal, capital, and labor in Table 3A.1, natural gas with CCS becomes economic at the prices of higher than 100$/t$CO_2$ for a range $2–6$/MMBtu natural gas prices. At the higher natural gas prices, coal with CCS becomes economic. A similar comparison has been developed by personnel at ExxonMobil.[4]

In the projections reported in Chapter 3, the EPPA model endogenously determines the prices for capital, labor, energy and other intermediate inputs. The relative economics of CCS is therefore changing over time based on a change in prices. CCS penetration in the model is also influenced by an additional factor that is used to limit the penetration rate of a new technology. This penetration-limiting factor allows economic rents to accrue to economic agents with knowledge to build a technology when it is still new and when there is no widespread technical knowledge to build cheaply at large scale. Initially, it leads to higher costs to represent first of the kind plants. As cumulative production increases (and experience is gained), the costs gradually decrease to the Nth plant cost.

## NOTES

[1]The EIA source is the U.S. Energy Administration *Assumptions to the Annual Energy Outlook, 2010 Early Release*. The EIA presents costs in $2008, which are converted here to $2005 (by a factor of 0.9218 using data from the U.S. Bureau of Economic Analysis (http://www.bea.gov)).

[2]The EIA wind and solar costs shown in the table are for a typical plant. In the EPPA model wind and solar are distinguished by scale. At low penetration levels they enter as imperfect substitutes for conventional electricity generation. The LCOE for wind without backup is reduced to $0.06/kWh in this study to reflect higher quality wind resources. Through the elasticity of substitution the model imposes a gradually increasing cost of production. The extension of wind capacity into lower quality resources is represented by wind plus biomass or NGCC backup technologies. The model does not distinguish between solar thermal and solar PV and the LCOE of $0.19/kWh is applied.

[3]Hamilton, M.R., 2009. An Analytical Framework for Long-Term Commercial Deployment and Innovation in Carbon Capture and Sequestration Technology in the United States, Master of Science Thesis, Technology and Policy Program, Massachusetts Institute of Technology.

[4]Kheshgi, H.S., N.A. Bhore, R.B. Hirsch, M.E. Parker, G.F. Teletzke and H. Thomann, 2010. Perspectives on CCS Cost and Economics, presented to Society of Petroleum Engineers, International Conference on $CO_2$ Capture, Storage and Utilization (SPE 139716) New Orleans, LA.

# Appendix 3B: Details of Simulation Results

| No Policy | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| | **2015** | **2020** | **2025** | **2030** | **2035** | **2040** | **2045** | **2050** |
| **Economy Wide Indicators** | | | | | | | | |
| Population (million) | 326 | 341 | 357 | 373 | 390 | 406 | 422 | 439 |
| GDP (trillion 2005$) | 15 | 17 | 19 | 22 | 25 | 28 | 32 | 36 |
| % Change GDP from Reference | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| GDP per capita (thousand 2005$) | 45 | 49 | 53 | 58 | 63 | 69 | 76 | 83 |
| Welfare (trillion 2005$) | 10 | 11 | 13 | 15 | 17 | 19 | 21 | 24 |
| % Change Welfare from Reference (EV) | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| $CO_2$-E Price (2005$/t$CO_2$-e) | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| **Prices (2005$)** | | | | | | | | |
| **Exclusive of Carbon Charge** | | | | | | | | |
| Oil Product ($/barrel) | 75.70 | 84.10 | 94.32 | 106.29 | 118.08 | 127.05 | 137.31 | 148.16 |
| Natural Gas ($/thousand cubic feet) | 6.39 | 6.86 | 7.40 | 8.05 | 8.63 | 9.16 | 9.76 | 10.37 |
| Coal ($/short ton) | 24.77 | 26.41 | 28.25 | 30.50 | 32.79 | 34.87 | 37.06 | 39.41 |
| **Inclusive of Carbon Charge** | | | | | | | | |
| Oil Product ($/barrel) | 75.70 | 84.10 | 94.32 | 106.29 | 118.08 | 127.05 | 137.31 | 148.16 |
| Natural Gas ($/thousand cubic feet) | 6.39 | 6.86 | 7.40 | 8.05 | 8.63 | 9.16 | 9.76 | 10.37 |
| Coal ($/short ton) | 24.77 | 26.41 | 28.25 | 30.50 | 32.79 | 34.87 | 37.06 | 39.41 |
| Electricity ($/kWh) | 0.10 | 0.11 | 0.12 | 0.12 | 0.13 | 0.13 | 0.14 | 0.14 |
| **GHG Emissions (mmt $CO_2$-e)** | | | | | | | | |
| GHG Emissions | 7282.3 | 7543.5 | 7820.8 | 8179.7 | 8571.1 | 8956.1 | 9340.2 | 9754.9 |
| $CO_2$ Emissions | 6252.2 | 6488.5 | 6726.2 | 7042.8 | 7378.8 | 7706.1 | 8028.8 | 8363.1 |
| $CH_4$ Emissions | 520.8 | 528.1 | 538.5 | 552.5 | 571.7 | 589.2 | 607.4 | 631.0 |
| $N_2O$ Emissions | 386.1 | 393.5 | 402.6 | 413.6 | 435.5 | 459.3 | 484.3 | 520.3 |
| Fluorinated Gases Emissions | 123.3 | 133.4 | 153.5 | 170.8 | 185.1 | 201.6 | 219.6 | 240.5 |
| **Primary Energy Use (qBtu)** | | | | | | | | |
| Coal | 21.3 | 22.5 | 23.7 | 25.2 | 26.9 | 28.4 | 29.9 | 31.5 |
| Oil | 41.4 | 42.2 | 43.1 | 44.4 | 45.8 | 47.2 | 48.6 | 50.1 |
| Natural Gas | 24.0 | 25.2 | 26.3 | 27.8 | 29.4 | 30.8 | 32.3 | 33.8 |
| Nuclear (primary energy eq) | 7.7 | 7.9 | 8.0 | 8.2 | 8.4 | 8.6 | 8.9 | 9.1 |
| Hydro (primary energy eq) | 2.5 | 2.5 | 2.4 | 2.3 | 2.3 | 2.3 | 2.4 | 2.5 |
| Renewable Elec. (primary energy eq) | 3.2 | 3.4 | 3.6 | 3.8 | 4.1 | 4.4 | 4.7 | 5.0 |
| Biomass Liquids | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| **Total Primary Energy Use** | 100.1 | 103.6 | 107.1 | 111.7 | 116.7 | 121.7 | 126.7 | 132.0 |
| **Reduced Use from Reference** | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| **Electricity Production (TkWh)** | | | | | | | | |
| Coal w/o CCS | 2.2 | 2.3 | 2.5 | 2.7 | 2.9 | 3.1 | 3.3 | 3.6 |
| Oil w/o CCS | 0.2 | 0.2 | 0.2 | 0.2 | 0.2 | 0.2 | 0.2 | 0.2 |
| Natural Gas w/o CCS | 0.6 | 0.7 | 0.7 | 0.7 | 0.8 | 0.8 | 0.9 | 1.0 |
| Nuclear | 0.8 | 0.8 | 0.9 | 0.9 | 0.9 | 0.9 | 1.0 | 1.0 |
| Hydro | 0.3 | 0.3 | 0.3 | 0.2 | 0.2 | 0.2 | 0.3 | 0.3 |
| Renewables | 0.3 | 0.4 | 0.4 | 0.4 | 0.4 | 0.5 | 0.5 | 0.5 |
| Natural Gas with CCS | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Coal with CCS | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| **Total Electricity Production** | 4.4 | 4.6 | 4.8 | 5.1 | 5.4 | 5.8 | 6.1 | 6.5 |

| Price Policy | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| | **2015** | **2020** | **2025** | **2030** | **2035** | **2040** | **2045** | **2050** |
| **Economy Wide Indicators** | | | | | | | | |
| Population (million) | 326 | 341 | 357 | 373 | 390 | 406 | 422 | 439 |
| GDP (trillion 2005$) | 15 | 17 | 19 | 21 | 24 | 27 | 31 | 35 |
| % Change GDP from Reference | -0.49 | -0.82 | -1.20 | -1.66 | -2.06 | -2.43 | -2.88 | -3.45 |
| GDP per capita (thousand 2005$) | 45 | 48 | 52 | 57 | 62 | 68 | 74 | 80 |
| Welfare (trillion 2005$) | 10 | 11 | 13 | 14 | 16 | 19 | 21 | 24 |
| % Change Welfare from Reference (EV) | -0.18 | -0.42 | -0.72 | -1.10 | -1.51 | -1.90 | -2.41 | -3.04 |
| $CO_2$-E Price (2005$/t$CO_2$-e) | 34.00 | 53.59 | 76.98 | 105.51 | 135.62 | 156.62 | 178.11 | 238.40 |
| **Prices (2005$)** | | | | | | | | |
| **Exclusive of Carbon Charge** | | | | | | | | |
| Oil Product ($/barrel) | 74.29 | 81.64 | 89.17 | 97.97 | 104.85 | 107.32 | 109.65 | 113.42 |
| Natural Gas ($/thousand cubic feet) | 6.15 | 6.51 | 6.91 | 7.51 | 8.23 | 8.61 | 8.99 | 8.77 |
| Coal ($/short ton) | 22.14 | 21.96 | 20.93 | 19.64 | 17.92 | 17.70 | 17.83 | 18.95 |
| **Inclusive of Carbon Charge** | | | | | | | | |
| Oil Product ($/barrel) | 89.65 | 105.86 | 123.95 | 145.65 | 166.12 | 178.09 | 190.13 | 221.14 |
| Natural Gas ($/thousand cubic feet) | 8.03 | 9.47 | 11.16 | 13.33 | 15.71 | 17.25 | 18.82 | 21.93 |
| Coal ($/short ton) | 91.77 | 131.71 | 178.61 | 235.74 | 295.68 | 338.48 | 382.62 | 507.23 |
| Electricity ($/kWh) | 0.13 | 0.15 | 0.17 | 0.19 | 0.21 | 0.22 | 0.24 | 0.26 |
| **GHG Emissions (mmt $CO_2$-e)** | | | | | | | | |
| GHG Emissions | 5797.3 | 5457.5 | 5117.0 | 4776.5 | 4436.1 | 4095.5 | 3754.8 | 3413.4 |
| $CO_2$ Emissions | 5197.3 | 4866.6 | 4534.9 | 4211.5 | 3888.9 | 3553.7 | 3216.0 | 2870.4 |
| $CH_4$ Emissions | 319.7 | 313.4 | 306.7 | 291.1 | 270.7 | 270.4 | 272.1 | 271.6 |
| $N_2O$ Emissions | 274.5 | 271.9 | 270.0 | 268.4 | 271.5 | 266.5 | 262.0 | 266.7 |
| Fluorinated Gases Emissions | 5.9 | 5.6 | 5.4 | 5.5 | 5.0 | 4.9 | 4.8 | 4.7 |
| **Primary Energy Use (qBtu)** | | | | | | | | |
| Coal | 15.1 | 12.3 | 9.2 | 5.4 | 0.7 | 0.4 | 0.6 | 0.8 |
| Oil | 37.0 | 35.9 | 34.9 | 33.8 | 32.3 | 24.3 | 16.2 | 13.0 |
| Natural Gas | 21.2 | 21.5 | 22.1 | 24.5 | 29.0 | 28.7 | 27.7 | 23.8 |
| Nuclear (primary energy eq) | 8.1 | 8.3 | 8.6 | 9.1 | 9.5 | 10.3 | 11.8 | 16.0 |
| Hydro (primary energy eq) | 2.9 | 3.0 | 3.1 | 3.2 | 3.3 | 3.4 | 3.5 | 3.7 |
| Renewable Elec. (primary energy eq) | 3.6 | 4.0 | 4.4 | 4.9 | 5.2 | 5.4 | 5.7 | 6.2 |
| Biomass Liquids | 0.0 | 0.0 | 0.0 | 0.0 | 0.1 | 4.1 | 8.2 | 9.5 |
| **Total Primary Energy Use** | 87.9 | 85.0 | 82.4 | 80.9 | 80.1 | 76.6 | 73.6 | 72.9 |
| **Reduced Use from Reference** | 12.2 | 18.6 | 24.7 | 30.8 | 36.5 | 45.1 | 53.1 | 59.0 |
| **Electricity Production (TkWh)** | | | | | | | | |
| Coal w/o CCS | 1.6 | 1.5 | 1.2 | 0.7 | 0.0 | 0.0 | 0.0 | 0.0 |
| Oil w/o CCS | 0.2 | 0.2 | 0.2 | 0.1 | 0.0 | 0.0 | 0.0 | 0.0 |
| Natural Gas w/o CCS | 0.6 | 0.8 | 1.0 | 1.5 | 2.3 | 2.3 | 2.2 | 1.7 |
| Nuclear | 0.9 | 0.9 | 0.9 | 1.0 | 1.0 | 1.1 | 1.3 | 1.7 |
| Hydro | 0.3 | 0.3 | 0.3 | 0.3 | 0.4 | 0.4 | 0.4 | 0.4 |
| Renewables | 0.4 | 0.4 | 0.5 | 0.5 | 0.6 | 0.6 | 0.6 | 0.7 |
| Natural Gas with CCS | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Coal with CCS | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| **Total Electricity Production** | 4.0 | 4.1 | 4.1 | 4.1 | 4.2 | 4.4 | 4.5 | 4.5 |

| Regulatory Policy | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| | **2015** | **2020** | **2025** | **2030** | **2035** | **2040** | **2045** | **2050** |
| **Economy Wide Indicators** | | | | | | | | |
| Population (million) | 326 | 341 | 357 | 373 | 390 | 406 | 422 | 439 |
| GDP (trillion 2005$) | 15 | 17 | 19 | 21 | 24 | 28 | 32 | 36 |
| % Change GDP from Reference | -0.01 | -0.26 | -0.53 | -0.74 | -0.87 | -0.99 | -1.04 | -1.05 |
| GDP per capita (thousand 2005$) | 45 | 49 | 52 | 57 | 63 | 69 | 75 | 82 |
| Welfare (trillion 2005$) | 10 | 11 | 13 | 14 | 16 | 19 | 21 | 24 |
| % Change Welfare from Reference (EV) | 0.03 | -0.14 | -0.38 | -0.61 | -0.78 | -0.91 | -1.00 | -1.04 |
| $CO_2$-E Price (2005$/t$CO_2$-e) | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| **Prices (2005$)** | | | | | | | | |
| **Exclusive of Carbon Charge** | | | | | | | | |
| Oil Product ($/barrel) | 75.31 | 83.00 | 92.02 | 102.64 | 112.83 | 119.76 | 127.44 | 135.13 |
| Natural Gas ($/thousand cubic feet) | 6.34 | 6.74 | 7.20 | 7.83 | 8.43 | 9.03 | 9.67 | 10.69 |
| Coal ($/short ton) | 22.80 | 22.08 | 21.98 | 22.18 | 22.45 | 22.62 | 22.89 | 23.16 |
| **Inclusive of Carbon Charge** | | | | | | | | |
| Oil Product ($/barrel) | 75.31 | 83.00 | 92.02 | 102.64 | 112.83 | 119.76 | 127.44 | 135.13 |
| Natural Gas ($/thousand cubic feet) | 6.34 | 6.74 | 7.20 | 7.83 | 8.43 | 9.03 | 9.67 | 10.69 |
| Coal ($/short ton) | 22.80 | 22.08 | 21.98 | 22.18 | 22.45 | 22.62 | 22.89 | 23.16 |
| Electricity ($/kWh) | 0.11 | 0.14 | 0.17 | 0.19 | 0.19 | 0.20 | 0.21 | 0.21 |
| **GHG Emissions (mmt $CO_2$-e)** | | | | | | | | |
| GHG Emissions | 6831.3 | 6515.2 | 6424.3 | 6476.8 | 6654.6 | 6870.6 | 7143.4 | 7466.9 |
| $CO_2$ Emissions | 5810.8 | 5484.8 | 5362.0 | 5376.6 | 5500.6 | 5663.9 | 5871.4 | 6120.0 |
| $CH_4$ Emissions | 512.9 | 508.9 | 513.0 | 522.6 | 540.3 | 554.4 | 573.1 | 591.2 |
| $N_2O$ Emissions | 384.9 | 389.8 | 398.2 | 409.7 | 432.2 | 455.0 | 484.1 | 520.5 |
| Fluorinated Gases Emissions | 122.7 | 131.7 | 151.2 | 167.9 | 181.5 | 197.3 | 214.9 | 235.3 |
| **Primary Energy Use (qBtu)** | | | | | | | | |
| Coal | 16.7 | 12.6 | 10.3 | 8.6 | 7.6 | 7.1 | 7.3 | 7.4 |
| Oil | 41.4 | 41.9 | 42.7 | 44.2 | 45.8 | 47.6 | 49.4 | 51.4 |
| Natural Gas | 23.9 | 24.6 | 25.2 | 26.6 | 28.6 | 30.2 | 31.2 | 33.1 |
| Nuclear (primary energy eq) | 7.9 | 8.3 | 8.6 | 9.1 | 9.2 | 9.4 | 9.8 | 9.9 |
| Hydro (primary energy eq) | 2.7 | 3.0 | 3.1 | 3.2 | 3.3 | 3.3 | 3.4 | 3.5 |
| Renewable Elec. (primary energy eq) | 4.4 | 6.7 | 8.5 | 10.0 | 11.0 | 11.9 | 12.7 | 12.4 |
| Biomass Liquids | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| **Total Primary Energy Use** | 97.1 | 97.1 | 98.5 | 101.7 | 105.4 | 109.5 | 113.9 | 117.8 |
| **Reduced Use from Reference** | 3.0 | 6.5 | 8.6 | 10.0 | 11.3 | 12.1 | 12.8 | 14.1 |
| **Electricity Production (TkWh)** | | | | | | | | |
| Coal w/o CCS | 1.9 | 1.5 | 1.3 | 1.1 | 1.0 | 0.9 | 0.9 | 0.9 |
| Oil w/o CCS | 0.2 | 0.2 | 0.2 | 0.2 | 0.3 | 0.3 | 0.3 | 0.3 |
| Natural Gas w/o CCS | 0.7 | 0.7 | 0.7 | 0.9 | 1.1 | 1.3 | 1.4 | 1.6 |
| Nuclear | 0.9 | 0.9 | 0.9 | 1.0 | 1.0 | 1.0 | 1.1 | 1.1 |
| Hydro | 0.3 | 0.3 | 0.3 | 0.3 | 0.4 | 0.4 | 0.4 | 0.4 |
| Renewables | 0.5 | 0.7 | 0.9 | 1.1 | 1.2 | 1.3 | 1.4 | 1.3 |
| Natural Gas with CCS | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Coal with CCS | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| **Total Electricity Production** | 4.3 | 4.3 | 4.4 | 4.6 | 4.9 | 5.1 | 5.4 | 5.6 |

## NOTES

Changes in Welfare are measured as equivalent variation (EV).

Oil numbers in primary energy use include the current generation biofuels (ethanol, biodiesel).

Biomass liquids refer to the second generation biofuels.

In Price Policy scenario, Natural Gas with CCS and Coal with CCS enter in 2045–2050 and produce 0.01–0.03 TkWh of electricity. See text of Chapter 3 for a sensitivity test with less costly CCS assumptions.

# Appendix 4A: Uncertainty in Natural Gas Consumption in Electricity

This appendix describes the use of the US-MARKAL Electric Sector model for uncertainty analysis of future natural gas consumption.

## MARKAL Model Structure

MARKAL[1] is an optimization framework that provides a general structure for modeling an energy system, and specific models consist of databases of the technologies, fuels, and end-use demands in the system. Any database developed for MARKAL contains the structure of the energy system to be modeled, including resource supplies, energy conversion technologies, and end-use demands. Also included are the technologies used to satisfy these demands with the data to characterize each of the technologies and resources used, including fixed and variable costs, technology availability and performance, and pollutant emissions.

Using straightforward linear programming techniques, MARKAL then calculates the best way to satisfy the specified demands, at least cost, subject to any constraints a user wishes to impose. Outputs of the model include a determination of the technological mix at intervals into the future, estimates of total system cost, energy services (by type and quantity), estimates of criteria and greenhouse gas (GHG) emissions, and estimates of energy commodity prices.

The US-EPA MARKAL model[2] is a model of the U.S. energy system from 2000 to 2050 in 5-year steps. For this study, we developed a version of US-EPA MARKAL that represents only the electric power sector, in which electricity demand and fuel inputs are exogenous. In this version, we have extended the original version to divide each year into 12 time slices, consisting of three seasons (summer, winter, spring/fall) and for each season four different times of day (night, morning, afternoon, peak).

For the reference (no uncertainty) case, we use the resulting electricity demand and fuel prices from the EPPA model analysis of Chapter 3 of this report. Moreover, the supply for natural gas and coal are based on an exogenous supply curve estimated from the same EPPA model version. The reference costs of new generation technologies use the same values as EPPA, based on the U.S. Energy Information Administration (EIA) 2010 values.[3]

The analyses presented below apply the "No Policy" and the "Price-Based" policy from Chapter 3. For each policy case, the resulting $CO_2$ emissions from the electric sector in the EPPA model are specified as the emission limits in MARKAL in each period. The resulting generation for the reference case under these two scenarios is shown in Chapter 4, Figures 4.2 and 4.3.

## Uncertainty Analysis Methodology

Using the US-EPA MARKAL Electric Sector model described above, we apply Monte Carlo simulation to propagate uncertainty in input assumptions through to uncertainty in outputs. Specifically, we represent uncertainty in electricity demand, fuel prices, and the costs of new generation technologies. For each of these parameters in the model, we have developed probability distributions from which values are randomly sampled.

The uncertainties in electricity demand and fuel prices are derived from the results of an uncertainty analysis of an earlier version of the EPPA model.[4] In that study, a Monte Carlo simulation of EPPA version 4 used randomly sampled values for over 100 parameters, including population growth, labor productivity growth, energy efficiency improvement, elasticities of substitution, and fossil fuel resources. Here we use the frequency distribution of electricity demand, natural gas price, and coal price over time, and normalize those distributions to have a mean of unity.

In the MARKAL analysis presented here, we sample from the normalized distributions to obtain an uncertainty factor, and multiply the reference input from EPPA by this factor to obtain a new sample value. This procedure is straightforward in the case of demand. Because the fuel supply is not modeled explicitly (the supply curve derived from the EPPA model is applied), we sample from a probability distribution centered on 1.0 to obtain a scaling factor, which is then used to multiply the prices for the supply curves to simulate shifting the curves up or down.

The uncertainty in the cost of future technologies is more challenging, since no data source exists. Usually, uncertainty studies rely on expert elicitation to obtain distributions, an endeavor that requires significant time and expense. For this study, we assumed simple, illustrative distributions for cost uncertainties. Distributions are developed for three canonical technology types, one with least uncertainty in cost, one with moderate uncertainty, and one with the greatest uncertainty.

All distributions utilize the Beta family of probability functions, and are skewed with longer upper tails (higher cost side).

The least uncertainty category assumes the cost uncertainty has a standard deviation of ±10% and 90% range of 0.9 to 1.3 relative to the reference assumption. This category includes new coal steam technologies and next generation natural gas power plants (combined cycle and combustion turbine).

The moderate uncertainty category assumes a distribution with a standard deviation of ±25% and a 90% range of 0.7 to 1.6 relative to the reference cost. This category includes nuclear light water reactors, coal integrated gasification combined cycle (IGCC), and wind technologies.

The largest uncertainty category assumes a distribution with a standard deviation of ±40% and a 90% range of 0.66 to 2.1 relative to the reference cost. This category includes technologies using carbon capture and storage (CCS), solar technologies, and advanced nuclear generation technologies.

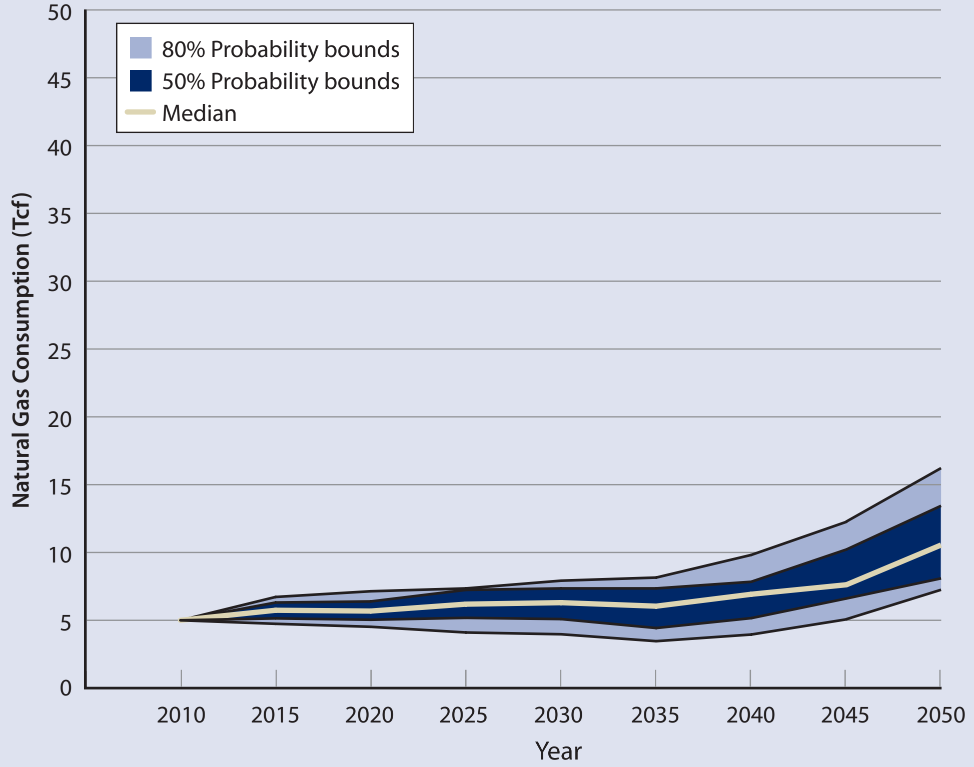
The sampling from these distributions is performed using Latin Hypercube to obtain a representative sample with fewer sample points. We use this approach to construct 400 sample scenarios. Each sample is used to simulate MARKAL under both the No Policy and the Price-Based Policy cases. The resulting consumption of natural gas, generation from each technology, and other results from these 400 runs are then used to construct frequency distributions to characterize the uncertainty in these projections.

## RESULTS

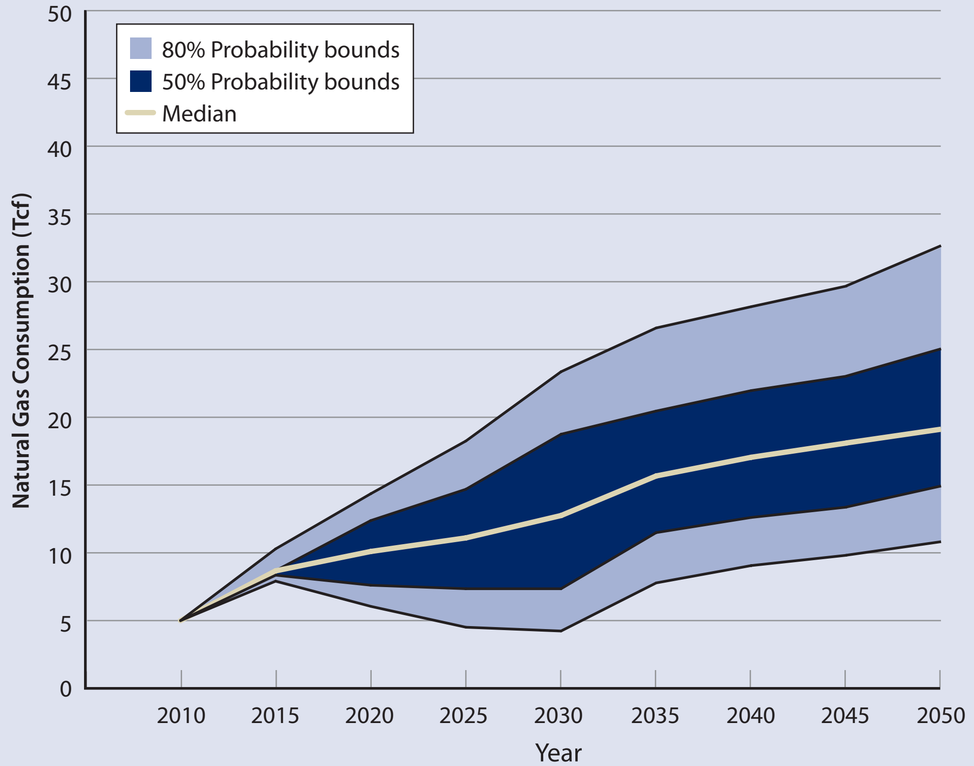
**Here, we present the resulting uncertainty in natural gas consumption. We summarize the uncertainty by giving the median consumption over time, the 50% probability interval, and the 80% probability interval.**

**Figure 4A.1 Natural Gas Use in U.S. Electricity Sector**

**With No Climate Policy**




**With Price-Based Climate Policy**



## NOTES

[1]Loulou, R., G. Goldstein, et al. (2004). "Documentation for the MARKAL Family of Models." *IEA Energy Technology Systems Analysis Programme*. Paris.

[2]U.S. EPA: MARKAL scenario analysis of technology options for the electric sector: The impact on air quality, U.S. Environmental Protection Agency, Washington, DC, EPA/600/R-06/114, available at: http://www.epa.gov/nrmrl/pubs/600r06114/600r06114.pdf (last access: March 2011), 2006.

[3]The EIA source is the U.S. Energy Administration Assumptions to the Annual Energy Outlook, 2010 Early Release. See also Appendix 3A of this report.

[4]Webster, M., A.P. Sokolov, J.M. Reilly, C.E. Forest, S. Paltsev, A. Schlosser, C. Wang, D. Kicklighter, M. Sarofim, J. Melillo, R.G. Prinn and H.D. Jacoby. 2009. Analysis of Climate Policy Targets under Uncertainty. MIT Joint Program Report #180, MIT Joint Program on the Science and Policy of Global Climate Change, Cambridge, MA.

# Appendix 5A: Natural Gas Use in Industrial Boilers

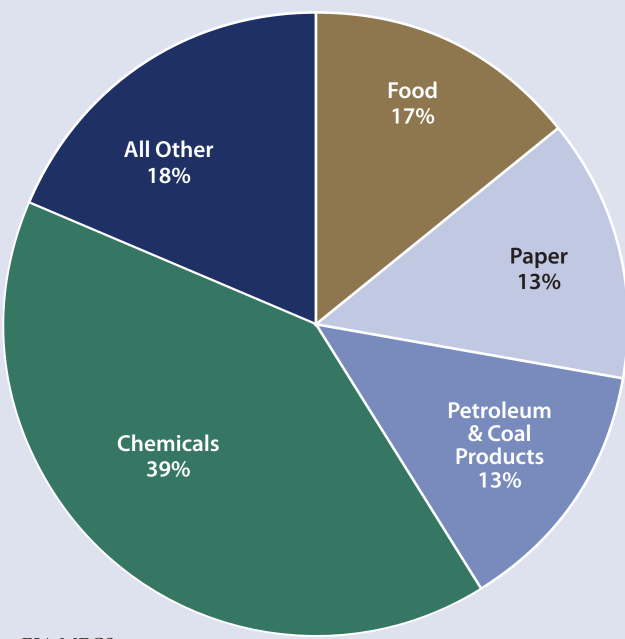
Industrial boilers consumed 2.1 Tcf of natural gas in 2006, accounting for 36% of total natural gas in manufacturing.[1] In this appendix, we provide further detailed analysis of two potential drivers affecting demand for natural gas in boilers: modernization of the current natural gas boiler fleet with more efficient units, and replacement of coal boilers with new natural gas boilers.

Figure 5A.1 shows that use of industrial boilers is concentrated in the energy-intensive industries, with the four largest applications in chemicals (39%); food processing (17%); paper (13%); and petroleum and coal products (13%). There is strong competition among boiler fuels in the energy-intensive industries, which employ larger boilers and have ready access to alternative fuel supplies. The EPA inventory shows, for example, 382 boilers greater than 100 MMBtu/hr, of which 68% were coal fired. Natural gas is the predominant boiler fuel in other manufacturing industries, which typically employ smaller boilers and do not have the same opportunities for use of by-product and waste fuels. The EPA data show 4,132 natural gas boilers, with an average size of 71 MMBtu/hr.[2]

For purposes of our analysis, we used a boiler size of 100 MMBtu/hr as a benchmark. A 100 MMBtu/hr boiler is at the large end of the scale of natural gas boilers; over 95% of existing boilers (all types and all fuels) are less than this size, comprising about 60% of total fuel input capacity (all fuels).[3] A boiler size of 100 MMBtu/hr is comparable to many coal boilers, which typically have a larger average size than natural gas. As a sensitivity analysis, we also analyzed smaller size boilers (50 MMBtu/hr).

**Figure 5A.1 Use of Natural Gas Boilers in the U.S. Manufacturing Sector**

**(Conventional and CHP/Cogeneration Boilers)**

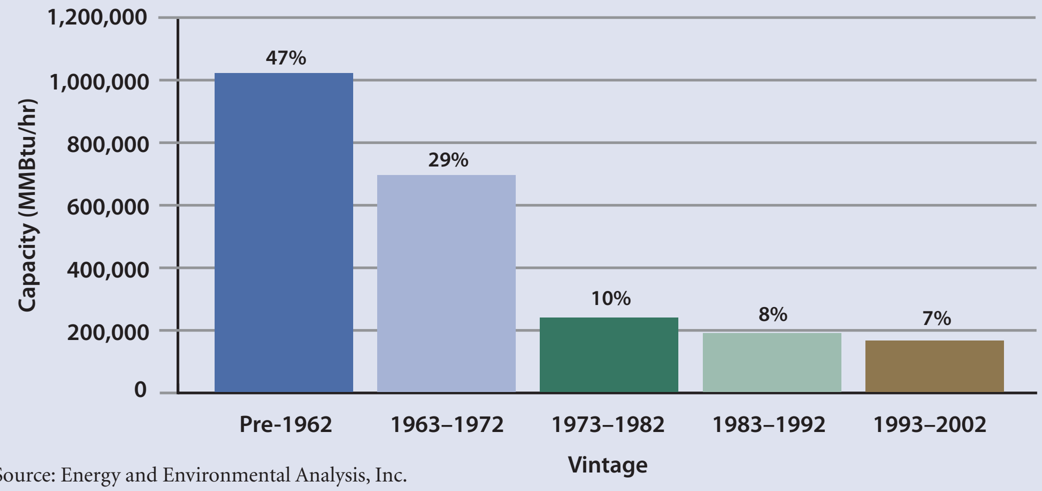



**"All Other" includes:**

- Beverage & Tobacco Products (1.4%)
- Textile Mills (1.6%)
- Textile Product Mills (0.7%)
- Apparel (0.2%)
- Wood Products (1.2%)
- Printing & Related Support (0.2%)
- Plastics & Rubber Products (2.7%)
- Nonmetallic Mineral Products (1.0%)
- Primary Metals (2.7%)
- Fabricated Metal Products (1.7%)
- Machinery (0.8%)
- Computer & Electronic Products (0.9%)
- Electrical Equipment, Appliances, & Components (0.3%)
- Transportation Equipment (1.9%)
- Furniture & Related Products (<0.1%)

Source: EIA MECS

**Figure 5A.2 Age Distribution of U.S. Industrial Boilers (All Types and Fuels)**




Source: Energy and Environmental Analysis, Inc.

## Modernization of the Natural Gas Industrial Boiler Fleet

Boilers have long service lives; about 85% of U.S. boilers have been in operation for about 30 years, and almost half of all boilers are nearly 50 years old, as illustrated in Figure 5A.2. There are a variety of existing boiler types and sizes. The two common types of boilers are firetube boilers, which are used primarily for hot water applications, and watertube boilers, which are for larger-scale, steam-generation applications.

Most existing natural gas boilers are typically non-condensing boilers, whose exhaust gases retain significant quantities of waste heat. These boilers typically have energy efficiencies in the range of 65% to 70%.[4] The waste heat in the exhaust gases consists of both the latent heat that can be recovered from condensing the water vapor into a liquid, as well as the sensible heat contained in the hot temperatures of the exhaust.

Since the mid-1980s, new natural gas boilers have incorporated additional heat recovery systems (i.e., condensing technology) to capture the latent heat and a portion of the sensible heat in the exhaust gases. In addition, use of economizers allows for waste heat to be recovered by pre-heating the boiler feedwater. These improvements boost overall energy efficiency to the 80% to 85% level. In 2004, the DOE set minimum energy-efficiency standards for new natural gas boilers in the range of 77% to 82%, depending upon boiler size and boiler technology.[5]

Further technology advances have demonstrated efficiency levels in the range of 94% to 95%. DOE cost shared RD&D with the Gas Technology Institute (GTI) has led to the commercialization of a "Super-Efficient" boiler capable of achieving 94% efficiency in firetube boilers.[6] The super boiler employs a multi-stage combustion system to improve combustion efficiency and reduce NOx emissions. This technology also incorporates a combination of a Transport Membrane Condenser (TMC) and compact humidifying air heater to extract more of the sensible as well as latent heat content of the exhaust gas.[7] In addition, DOE and GTI have collaborated on RD&D on another technology, the Ultramizer System.[8] The Ultramizer consists of a TMC condenser combined with high-temperature and low-temperature waste heat recovery systems that preheat the boiler feedwater and provide additional make-up water recovered from the exhaust gas. Boiler efficiencies of 95% are possible for both firetube and watertube boiler applications.[9]

We compared the net present value costs, pre-tax, of potential replacement with either a high-efficiency or super-high-efficiency natural gas boiler for an existing 100 MMBtu/hr natural gas boiler. Our analysis employed equipment capital costs and energy-efficiency assumptions provided by the GTI,[10] combined with the 2010 average natural gas price for industrial delivery of $5.19 per mcf. The results under these assumptions (Table 5A.1) show that replacement of current natural gas boilers with high-efficiency models would, at a 15% discount rate, yield a reduction of 8% in annualized costs on a pre-tax basis. Replacement with super-high-efficiency boilers would yield annualized savings of 20%. A sensitivity analysis comparing 50 MMBtu/hr natural gas boilers yielded similar results.

The payback periods for these boiler replacements range from 1.8 to 3.6 years, based on 2010 actual industrial natural gas prices, and assuming no increase in natural gas prices over this period. Higher natural gas prices would improve the results; lower natural gas prices would reduce the projected annualized savings and extend the payback period.

The addition to these equipment expenditures of soft costs (management, supervision, etc.) and expenses attending the change in particular installations will reduce these returns somewhat. Also, in particular instances, the attractiveness of boiler modernization will depend on other factors such as the remaining book value of existing boilers that a firm might write off; the availability of investment capital; the return on investment in boiler modernization relative to other opportunities; and the availability of tax incentives, such as accelerated depreciation or investment tax credits. Considering all these factors, however, it appears that replacement will be cost effective in many installations.

**Table 5A.1 Cost Comparison of Natural Gas Boiler Modernization Options**

| | | Existing Natural Gas Boiler | Replacement Natural Gas Boiler | |
|---|---|---|---|---|
| Parameter | Units | Base Case | High Efficiency (80%) | Super High Efficiency (94%) |
| **Assumptions** | | | | |
| Boiler Size | MMBtu/hr | 100 | 100 | 100 |
| Boiler Capital Cost | $ million | — | 1.00 | 1.25 |
| Natural Gas Fired Boiler Efficiency | % | 70 | 80 | 94 |
| 2010 Industrial Natural Gas Price | $/MMBtu | 5.19 | 5.19 | 5.19 |
| **Economic Results** | | | | |
| Net Present Value of Costs | $ Million | **22.9** | **21.0** | **18.3** |
| Payback Period | Years | — | **3.6** | **1.8** |
| **Impact on $CO_2$ Emissions** | | | | |
| $CO_2$ Emissions | Tons $CO_2$/yr | 35,616 | 31,164 | 26,523 |
| Reduction in $CO_2$ Emissions | Tons $CO_2$/yr | — | **4,452** | **9,093** |

Source: MIT

Two scenarios can provide an indication of the impact on natural gas consumption: (1) a replacement of 50% of current natural gas industrial boiler capacity with high-efficiency natural gas boilers would reduce demand for natural gas by 129 Bcf annually, while (2) a replacement of 50% of current natural gas boiler capacity with super-high-efficiency natural gas boilers would reduce demand by 263 Bcf annually. The reduction in $CO_2$ emissions ranges from about 4,500 to over 9,000 tons per year per boiler.

These results show that replacement of existing industrial natural gas boilers with higher efficiency models could cost-effectively reduce natural gas demand and reduce GHG emissions, suggesting that the DOE should review the current energy-efficiency standards for commercial and industrial natural gas boilers and assess the feasibility of setting a more stringent standard.

### Replacement of Existing Coal Industrial Boilers with Efficient Natural Gas Boilers

A $CO_2$ emissions reduction requirement could lead to a significant level of replacement of existing coal boilers to natural gas. Absent a carbon constraint, a potential driver for fuel switching of coal boilers to natural gas is the establishment of National Emissions Standards for Hazardous Air Pollutants (NESHAPS) for boilers which could lead to a similar result.

Our analysis is based on the EPA February 23, 2011, emissions standards for mercury, metals, dioxin, acid gases, and other hazardous air pollutants emitted from industrial boilers and process heaters. On May 16, 2011, EPA Administrator Jackson stayed the implementation of the standards to provide for additional review; however, the February 23 standards, and the June 2010 proposed standards, provide a general benchmark for analysis of the trade-offs between retrofitting existing industrial coal boilers with post-combustion controls and replacement of existing industrial coal boilers with efficient, new natural gas boilers.

The Clean Air Act requires that emissions reduction standards for each hazardous air pollutant be based upon the emissions reductions that can be attained through installation of the Maximum Achievable Control Technology (MACT), which is defined as the level of performance achieved by the top 12% performing facilities within the subcategory of facilities subject to the standards. The EPA defined 15 different subcategories of industrial boilers and process heaters, setting standards for 11 of the 15 subcategories; existing natural gas boilers (as well as boilers fueled with refinery gas and certain other types of clean gases) fall within the four subcategories for which there are no specific emissions standards. EPA estimates of the emissions reductions achievable from application of the proposed standards are shown in Table 5A.2.

**Table 5A.2 Estimated National Emissions Reductions from the February 2011 MACT Standards for Industrial Boilers and Process Heaters**

| Hazardous Air Pollutant | Annual Emissions Reductions (Tons/yr) |
|---|---|
| Hydrogen Chloride | 30,000 |
| Mercury | 1.4 |
| Non-mercury Metals | 2,700 |
| Particulate Matter | 47,000 |
| Sulfur Dioxide | 440,000 |
| Volatile Organic Compounds | 7,000 |

Source: EPA

Three subcategories subject to new MACT standards are coal boilers utilizing different technologies — stoker, fluidized bed, and pulverized coal combustion. Achieving the emission standards for coal boilers will require the installation of wet scrubbers and fabric filters. Installation of activated carbon injection for control of mercury emissions also may be required, although the EPA noted that it is assuming that the units subject to the MACT calculations were able to achieve the standards for mercury emissions reductions through the use of fabric filters only.

At that time of the initial proposed rules in June 2010, the EPA also analyzed fuel switching from coal to natural gas as a compliance option,[11] but concluded that this measure was uneconomical relative to the installation of post-combustion control technology at coal boilers. This EPA conclusion was heavily influenced by two assumptions that were disadvantageous to natural gas: (1) the analysis used the 2008 average natural gas price for industrial delivery of $9.58 per mcf, which represented a period of high natural gas prices relative to today and anticipated in the future (see Chapter 3); and (2) the analysis assumed that boiler owners would retrofit the burners on existing coal boilers to burn gas rather than replace the boilers entirely with new high-efficiency boilers designed for natural gas. The EPA estimates that burner retrofit reduced boiler energy efficiency by 5%.

We performed a similar analysis for a single 100 MMBtu/hr coal boiler, a relatively large boiler that can be deployed in a number of industry sectors. Four different options were analyzed and compared to a base case. The four options include: (1) retrofit of post-combustion controls (using EPA cost assumptions); (2) retrofit of natural gas burners within the existing coal boiler (using EPA efficiency assumptions); (3) replacement of the existing coal-fired boiler with a high-efficiency natural gas boiler; and (4) replacement of the existing coal boiler with one of the new, super-high-efficiency natural gas boiler technologies.

**Table 5A.3 Cost Comparison of Industrial Boiler MACT Compliance Options**

| | | Existing Coal Boiler | | | Replacement Natural Gas Boiler | |
|---|---|---|---|---|---|---|
| Parameter | Units | Base Case | Post-Combustion Controls Retrofit | Natural Gas Burner Retrofit | High Efficiency (80%) | Super High Efficiency (94%) |
| **Assumptions** | | | | | | |
| Boiler Size | MMBtu/hr | 100 | 100 | 100 | 100 | 100 |
| Boiler Capital Cost | $ Million | — | 5.5 | 0.34 | 1.00 | 1.25 |
| Coal-Fired Boiler Efficiency | % | 65 | 65 | — | — | — |
| Natural Gas Fired Boiler Efficiency | % | — | — | 62 | 80 | 94 |
| 2010 Industrial Coal Price | $/MMBtu | 2.88 | 2.88 | — | — | — |
| 2010 Industrial Natural Gas Price | $/MMBtu | — | — | 5.19 | 5.19 | 5.19 |
| **Economic Results** | | | | | | |
| Net Present Value of Costs | $ Million | **12.7** | **18.2** | **24.4** | **19.6** | **17.1** |
| **Impact on $CO_2$ Emissions** | | | | | | |
| $CO_2$ Emissions | Tons $CO_2$/yr | 63,840 | 63,840 | 37,339 | 28,938 | 24,628 |
| Reduction in $CO_2$ Emissions | Tons $CO_2$/yr | 0 | 0 | **26,501** | **34,902** | **39,212** |
| Incremental Cost of $CO_2$ Reductions | $/Tons $CO_2$ | — | — | **34** | **5** | **-5** |

Source: MIT

Table 5A.3 shows the results, including the net present value at a 15% discount rate and effects on $CO_2$ emissions. The capital cost shown in the table is the cost of equipment, and for the purposes of this comparison it is reasonable to assume that the soft costs and other costs attending the particular firm or installation are roughly the same. The option of retrofitting natural gas burners in existing coal boilers (i.e., the option analyzed by the EPA) was the highest cost option on a net present value basis.[12] The reason is that there is a small energy-efficiency penalty from retrofitting natural gas burners, and thus total fuel costs are higher. This finding is consistent with the EPA regulatory analysis. Replacement of the existing coal boilers with high-efficiency natural gas boilers (i.e., 80% efficiency) is slightly more expensive than installing post-combustion controls, but boiler replacement with a super-high-efficiency (i.e., 94% efficiency) natural gas boiler is more cost-effective. A sensitivity analysis comparing smaller size boilers (50 MMBtu/hr) yielded similar results.

This cost comparison is dependent upon two assumptions: (1) the estimates of capital equipment cost for retrofitting post-combustion controls for coal; and (2) the relative prices of coal and natural gas. Our analysis uses the EPA capital cost assumptions for installation of post-combustion controls at coal boilers, consisting of wet scrubbers and fabric filters, but without activated carbon injection. For coal boilers that may require additional controls to achieve MACT limits for mercury emissions, costs would increase substantially, making the options for replacement with natural gas boilers much more cost-effective. The comparative results also are sensitive to natural gas prices. The price differential between coal and natural gas used in our analysis was \$2.31/MMBtu, based on actual average delivered prices in 2010. A lower price differential (i.e., a smaller price spread between natural gas and coal) would make conversion to natural gas more attractive.

The potential impact of replacing industrial coal boilers with new, high-efficiency natural gas boilers is significant. The EIA MECS data show that industrial coal boilers and process heaters currently use 892 trillion Btu (0.9 quads) of coal each year. Conversion of this capacity to natural gas would increase demand for natural gas by 0.87 Tcf per year. The actual rate of market penetration would be dependent upon individual facility analyses.

Replacement of existing coal boilers with new efficient natural gas boilers in order to meet NESHAPS requirements could reduce annual $CO_2$ emissions by 52,000 to 57,000 tons per year per boiler. Assuming that high-efficiency (i.e., 80%) natural gas boilers are installed, the net present value cost is slightly higher than installing post-combustion controls. If this incremental cost is assigned solely to $CO_2$ reduction (ignoring the benefits from further reductions of other pollutants), the incremental cost to achieve the $CO_2$ reductions is about \$5/ton.

## NOTES

[1]U.S. Energy Information Administration, 2008 Manufacturing Energy Consumption Survey.

[2]U.S. EPA Industrial/Commercial Boiler Survey.

[3]Energy and Environmental Analysis, Inc., "Characterization of the U.S. Industrial Boiler Population," Report prepared for Oak Ridge National Laboratory, May 2005.

[4]Energy Efficiency in boilers is measured as AFUE or Average Fuel Use Efficiency.

[5]The DOE Energy Efficiency Standards can be found at 10 CFR Part 431.

[6]DOE Webcast: GTI Super Boiler Technology, by Dennis Chojnacki, Senior Engineer and Curt Bermel, Business Development Manager R&D, Gas Technology Institute, November 20, 2008.

[7]U.S. Department of Energy, Industrial Technologies Program, Super Boiler, June 2007.

[8]See http://www.cannonboilerworks.com.

[9]GTI licensed its patented Transport Membrane Condenser (TMC) to Cannon Boiler Works on October 6, 2009. Cannon Boiler Works announced plans to release the Ultramizer technology to the public around the end of 2010. See http://www.cannonboilerworks.com/ultramizer.html.

[10]Ron Edelstein, Gas Technology Institute, personal communication.

[11]The EPA analysis was summarized in an April 10, 2010 Memorandum from Graham Gibson, ERG, to Jim Eddinger, U.S. EPA.

[12]The analysis in Table 5A.3 is drawn from a variety of data, including the ERG Memorandum of April 10, 2010; the GTI data; the EPA regulatory analysis, which can be found at http://epa.gov/ttn/atw/boiler/boilerpg.html; coal and natural gas prices can be found at http://www.eia.doe.gov. The net present value estimates are based on a discount rate of 15%, representing a typical internal rate of return for analysis of corporate capital investments.

# Appendix 5B: Demand for Natural Gas and Natural Gas Liquids (NGLs) as Feedstock in the Chemicals Industry

This appendix discusses demand for natural gas and NGLs as a feedstock, focusing on the manufacturing of bulk chemicals for use in petroleum refining, fertilizers, and plastics. These are highly competitive global industries, operating at large volumes with relatively small margins. They are both capital-intensive and energy-intensive industries. Thus, in the short term, production levels and demand for natural gas and NGL feedstock can be highly elastic with respect to the price of natural gas and NGLs. Over the longer term, changes in demand will be dependent upon allocation of capital investment in new plant capacity.

In this appendix, we provide a qualitative and selected quantitative analysis of several key technical and economic relationships affecting U.S. demand for natural gas and NGLs as a feedstock material for bulk chemicals manufacturing. We also describe the principal global market factors that affect U.S. demand for bulk chemicals manufacturing. Our analysis is intended to supplement the EPPA modeling analysis presented in Chapter 3.

The current demand for natural gas and NGLs in the U.S. chemicals industry sector is summarized in Table 5B.1, which shows that about 20% of natural gas used in U.S. chemicals manufacturing is used as a feedstock; virtually all NGLs are used as feedstock.

The two principal feedstock uses of natural gas are in the manufacturing of ammonia for fertilizer products and the production of hydrogen for use in petroleum refining. NGLs are used in a variety of chemicals and plastics; in this appendix, we focus on the use of ethane in the production of ethylene, an intermediate product used to manufacture a variety of plastics. We discuss each of these three principal uses in the sections that follow.

## Hydrogen Production from Natural Gas

Hydrogen production from natural gas accounted for 143 Bcf of natural gas use in 2009.[1] Although 2009 consumption declined from 2008 levels, both the historical trend and future projections indicate growing demand for natural gas for

**Table 5B.1 Natural Gas and NGL End Uses in U.S. Chemicals Industry**

| Chemicals Industry Demand | | |
|---|---|---|
| | Natural Gas | NGL/LPG |
| | bcf | 1 Million bbl |
| Fuel | 1,355 | 5 |
| Feedstock | 342 | 644 |
| **Total** | **1,697** | **649** |
| **% Feedstock** | **20%** | **99%** |

Source: EIA MECS

hydrogen production in petroleum refineries. On-site, refiner-owned, hydrogen plant capacity has increased by 59% since 1982, representing an average growth rate of 1.2% per year.[2] The production and use of heavier crude oils and demand for cleaner petroleum products have combined to increase the requirements for hydrogen in the refining process to maximize the value of hydrocarbon product slates. Several studies project the near-term growth rate of hydrogen consumption to be about 4% per year; these studies also project merchant hydrogen plants taking a greater share of future growth.[3]

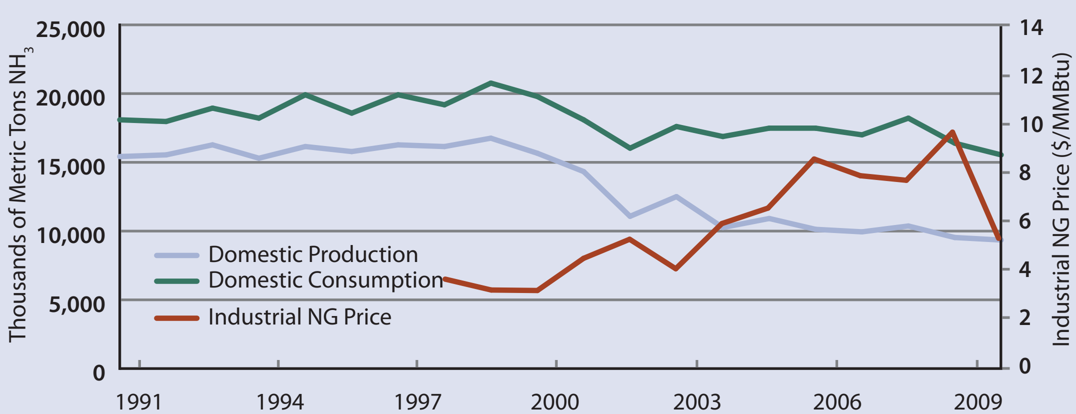
### Natural Gas Use for U.S. Ammonia Manufacturing in the Fertilizer Industry

Natural gas is the principal feedstock for the manufacturing of ammonia, an intermediate product primarily used in the manufacture of nitrogenous fertilizers. The initial step involves the production of hydrogen through the steam reforming of natural gas. Hydrogen and nitrogen are then reacted through the Haber-Bosch process to produce ammonia. Ammonia is an intermediate product that can be converted to a variety of other compounds to be used as fertilizer. These include urea, nitric acid, ammonium nitrate, and ammonium sulfate.

Demand for natural gas in ammonia production is determined by demand for nitrogenous fertilizers for agriculture, as well as competition between domestic production and imports of ammonia and fertilizer products. Figure 5B.1 shows that total domestic consumption of ammonia had been relatively constant over the decade of the 1990s, experienced a dip in the 2000 to 2001 time frame and then remained relatively constant until the 2008 to 2009 recession. The trend analysis also shows that domestic natural gas prices rose sharply after 2000, weakening the competitive position of domestic ammonia producers relative to international competition.

Lower demand combined with increased imports resulted in a significant decline in domestic production. Figure 5B.2 shows that the number of ammonia plants in the U.S. decreased from 45 (in 1990) to 22 (by the end of 2007). This decline occurred in several stages. During the 1990s, smaller plants were displaced by larger, more efficient plants while total domestic ammonia production remained steady at around 16,000 tons per year.

**Figure 5B.1 Trends in the U.S. Ammonia Market and Natural Gas Prices**

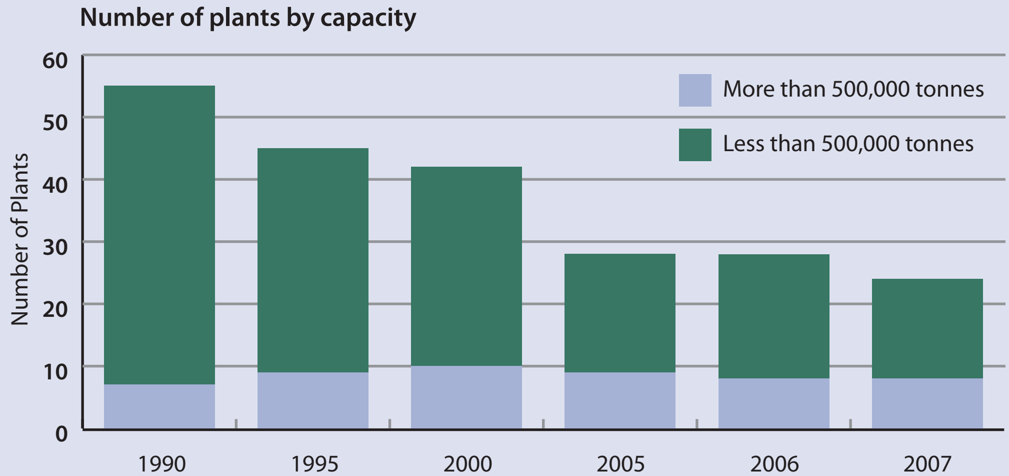



Sources: USGS, EIA

Beginning in 2000, total demand for fertilizer declined, and imports increased, leading to a second wave of plant closures as imports captured an increasing share of the domestic market. By 2003, total domestic production was reduced to 10,000 tons per year, 37.5% less than the average production of 16,000 tons per year in the 1990s.

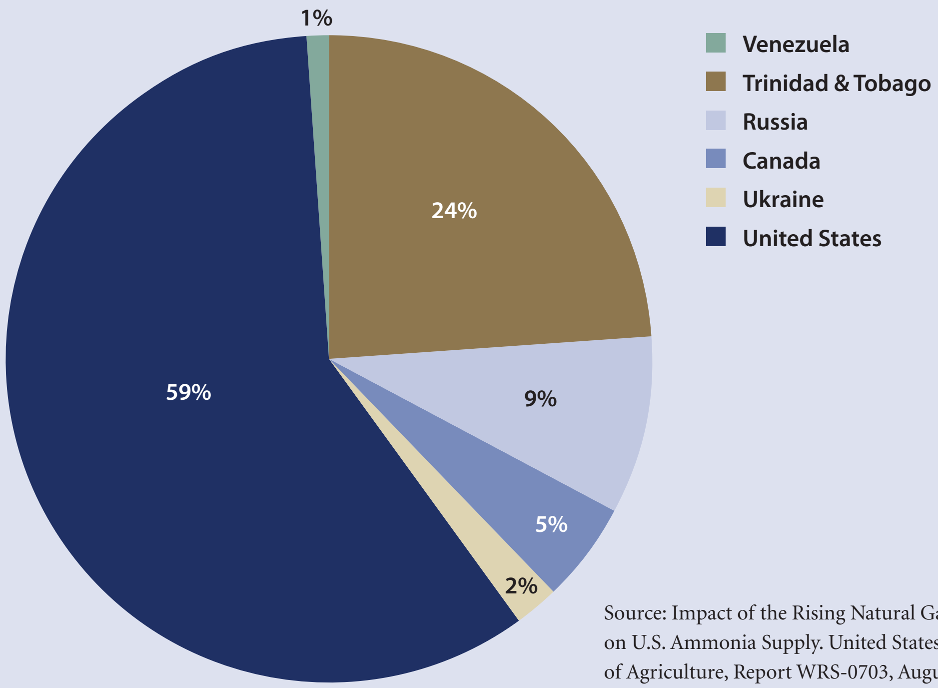
The market share of ammonia imports increased from about 15% in 1998 to 41% in 2007. The current sources of ammonia imports are shown in Figure 5B.3.

**Figure 5B.2 Trends in U.S. Ammonia Manufacturing Capacity**




Source: USDA

**Figure 5B.3 2007 Sources of U.S. Ammonia Consumption**




Source: Impact of the Rising Natural Gas Prices on U.S. Ammonia Supply. United States Department of Agriculture, Report WRS-0703, August 2007.

**Table 5B.2 International Comparison of Ammonia Manufacturing Costs**

| | 2007 Industrial Price of Natural Gas | Plant Efficiency | Manufacturing Costs | Maritime Freight Rates | Cost of Ammonia | Total Production | Exports to US |
|---|---|---|---|---|---|---|---|
| **Country** | **\$/GJ** | **GJ/ton $NH_3$** | **\$/ton $NH_3$** | **\$/ton $NH_3$** | **\$/ton $NH_3$** | **ton $NH_3$** | **ton $NH_3$** |
| Venezuela | 1.00 | 38.6 | 30 | 35.0 | 104 | 1,200 | 270 |
| Trinidad & Tobago | 2.50 | 38.6 | 30 | 30.0 | 157 | 5,100 | 4,360 |
| Russia | 1.00 | 40.4 | 30 | 87.5 | 158 | 12,800 | 1,640 |
| Canada | 5.85 | 33.1 | 50 | 0.0 | 244 | 4,100 | 920 |
| Ukraine | 5.20 | 40.4 | 30 | 87.5 | 328 | 5,100 | 350 |
| United States | 7.68 | 38 | 50 | 0.0 | 342 | 10,750 | — |
| **U.S. Sensitivity Analysis** | | | | | | | |
| 2007 Prices | 7.68 | 30 / 40 | 50 | 0.0 | 280 / 357 | — | — |
| 2010 Prices | 5.30 | 30 / 40 | 50 | 0.0 | 209 / 262 | — | — |

Source: Maritime freight rates are from Potash Corporation, Overview of Nitrogen Markets. Prices of natural gas are from Natural Resources Canada, Review of 2007/2008 North American natural gas demand, and from Potash Corporation, The N-P-K Outlook 2006, and from the 2009 Q1 Market Analysis. Some of these prices are further quotes from Fertecon, a consultancy specialized in fertilizer markets. Manufacturing costs are from the Kirk-Othmer Encyclopedia of Chemical Technology. Average plant efficiencies are adapted from a study by the Canadian Industry Program for Energy Conservation: Benchmarking Energy Efficiency and Carbon Dioxide Emissions.

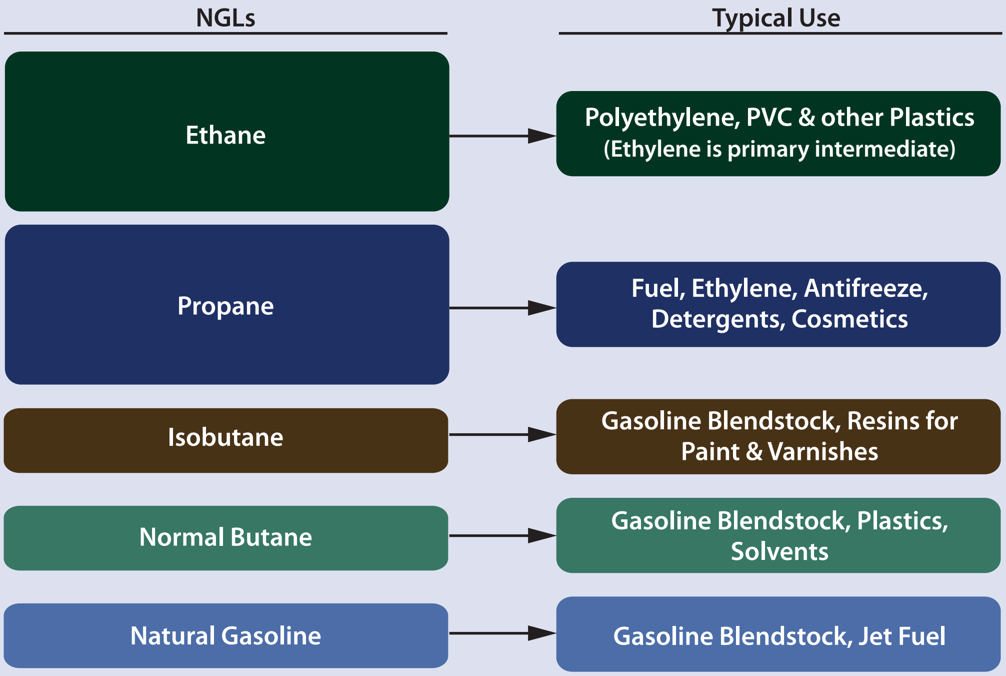
Ammonia exporting countries benefit from lower natural gas costs, attributable to either relatively large natural gas supplies relative to native markets, or artificially low prices due to government controls. Trinidad & Tobago has a large, low-cost, natural gas resource base with no local market; the gas needs either to be exported as LNG or converted to a value-added product such as ammonia and then exported. Venezuela, Ukraine, and Russia ammonia producers have benefited from artificially low natural gas prices regulated by their respective governments; the Russian government is now taking steps to allow Russian natural gas prices to rise to market levels.

We performed a comparison of the cost of ammonia-producing countries to export to the U.S. market. The analysis, based on 2007 data, is summarized in Table 5B.2.[5]

The estimates for 2007 show that, at that time, domestic ammonia production costs were higher than those of the countries exporting to the U.S. Updating the domestic cost estimates to reflect 2010 natural gas prices shows that the highly efficient U.S. manufacturing plants can produce ammonia at \$209/ton, placing them in a more competitive range. At that level, domestic production costs remain higher than Caribbean producers, but lower than Ukraine. Thus, the recent decline in U.S. natural gas prices places the remaining domestic ammonia producers in a more competitive posture relative to imports. Removal of artificial price controls on natural gas in foreign ammonia producers would further improve the competitive position of U.S. ammonia producers.

We did not attempt to project future domestic demand for ammonia. This would require a detailed analysis of future patterns of global trade in agricultural commodities, levels of U.S. agricultural production by type of crop, potential for changes in agricultural practices, and alternatives to conventional nitrogenous fertilizer products. We note that one factor that could lead to an increase in domestic demand for fertilizer (and thus ammonia) is the production of ethanol to meet statutory renewable fuel mandates. For example, expanding domestic ethanol production to supply 15% of total transportation fuel consumption will lead to an increase in natural gas usage both as a feedstock for ammonia production and as a fuel for corn processing.

**Figure 5B.4 Common Uses of NGL Components**




Source: EIA, Morgan Stanley Research

## U.S. Demand for Natural Gas Liquids as a Feedstock for Manufacturing of Bulk Chemicals

NGLs are mixtures of several different higher molecular weight hydrocarbons that are obtained from three primary sources: co-production with natural gas, by-products from crude oil refining, and imports. Over 70% of NGL supply is from natural gas production, with most of the remainder resulting as a by-product of the petroleum-refining process. Ethane and propane are the largest constituents of NGLs, with lesser amounts of butanes, pentane, and natural gasoline. Figure 5B.4 shows the principal chemical constituents of NGLs and their common uses.

Ethane is the primary constituent of NGLs and is a good indicator of demand for NGLs. Ethane is converted into ethylene and other olefins through an energy-intensive process known as "cracking." Ethylene is an intermediate product that ultimately is converted into a variety of products, primarily polyethylene. Ethylene also can be produced from naphtha, an intermediate product from crude oil refining. Thus, demand for ethane, the largest single ingredient of NGLs, is determined by total demand for polyethylene (the principal ultimate product) and the competition between use of ethane and naphtha as a feedstock in the manufacturing of ethylene.

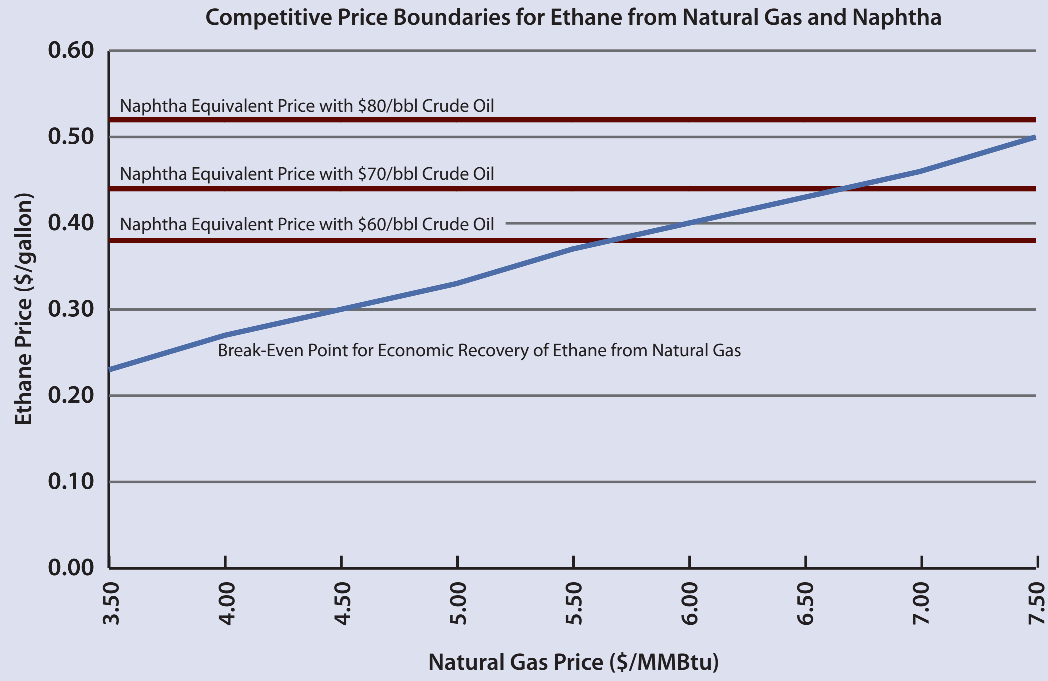
For the 2000 to 2009 period, global demand for polyethylene increased by 2.5% per year, a rate that was 90% of the global GDP growth rate. However, the global average masked significant regional variation. U.S. demand for polyethylene declined while Chinese demand more than doubled, making China the world's largest consumer of polyethylene. Current projections suggest that global growth in demand for polyethylene will exceed the rate of growth in global GDP; however, U.S. demand for polyethylene will at best be equal to domestic

GDP growth. U.S. demand for polyethylene increased by 9% in 2010, relative to a depressed 2009 market, and growth is expected to be close to expected average U.S. GDP growth rates of 2.0% to 2.5% per year over the next five years.[6] Thus, U.S. GDP growth sets one of the principal markers for growth of demand for polyethylene, ethylene, and ultimately for NGLs.

The other key indicator of demand for NGLs is the price differential between ethane, which is priced relative to natural gas, and naphtha, which is priced relative to oil. Feedstock costs comprise approximately 80% of the cost of ethylene, so any difference in the pricing of ethane relative to naphtha has a significant impact on demand.

We performed an analysis of the relative economics of using NGL-based ethane or crude oil-based naphtha as a feedstock for ethylene production. Figure 5B.5 shows that ethane is economically advantageous relative to naphtha; the wellhead price of natural gas would need to reach \$7.50/mcf, relative to a crude oil price of \$80/bbl, before naphtha would be cost competitive with ethane as a feedstock for ethylene manufacturing. This break-even analysis represents a ratio of oil to natural gas prices of slightly over 10 to 1; most industry observers use a rule of thumb of 8 to 1 as the benchmark for determining when lighter natural-gas-based feedstock such as ethane have an advantage over crude oil-derived naphtha.[7] Recently, this ratio has hovered around 20 to 1 (see Chapter 7).

**Figure 5B.5 Competitive Price Boundaries for U.S. Ethylene Production from Natural Gas and Naphtha**




Source: MIT, based on Morgan Stanley data

**Table 5B.3 Potential Increase in Near-Term Demand for NGLs for Domestic Ethylene Manufacturing**

| Scenarios | Scenario 1: No polyethylene growth; NGL displaces naphtha | Scenario 2: Polyethylene growth, with no change in NGL/ naphtha shares | Scenario 3: Polyethylene growth; NGL displaces naphtha |
|---|---|---|---|
| **Assumptions** | | | |
| U.S. Polyethylene Growth (CAGR) | 0% | 3% | 3% |
| NGL/Naphtha Feedstock Share | 100% NGLs | 85%/15% | 100% NGLs |
| **Impact on NGL Demand** | | | |
| NGL Demand Increase | +7.6% | +12.2% | +25% |

Using the assumptions regarding U.S. polyethylene demand and ethane/naphtha cost differentials, we developed estimates of the potential increase in demand for NGLs to meet domestic U.S. requirements. We considered three scenarios, combining different assumptions for growth in U.S. polyethylene demand and feedstock mix of NGLs relative to naphtha. Table 5B.3 indicates that under these three scenarios, demand for NGLs could increase by up to 25% in the near term.

This is a conservative estimate of potential increase in domestic NGL demand because it considers U.S. demand only, and does not consider the potential for growth in exports. Over the past decade, the growth in global demand for polyethylene, which has been increasing at a faster rate than in the U.S., has been served by the growth in bulk chemicals production in the Middle East. Projections show that the Middle East may account for up to one-third of new capacity additions in the short term (2010 to 2014).[8] However, some forecasts suggest that the Middle East producers may be close to fully utilizing their low-cost opportunities to produce bulk chemicals.[9] This could create an opportunity for U.S. chemical manufacturers, which currently export about 20% of global production,[10] to serve additional demand in Asian and other developing countries, in addition to domestic market requirements. Recent press reports reflect the change in economic competitiveness of domestic petrochemicals manufacturing. Demand for ethylene increased in 2010 by 8% globally and by 6% in the U.S.[11] Domestic companies are looking to restart idled capacity or switch existing capacity from naphtha to ethane, consistent with the projections in Table 5B.3. In addition, there are reports that several firms are studying the feasibility of adding new domestic ethylene cracking capacity, as expansions to existing facilities and, in at least one case, an entirely new facility.[12]

Another factor that will affect U.S. demand for natural gas and NGLs feedstock is the relationship between the location of bulk chemicals manufacturing and the manufacturing of value-added specialty chemicals from the bulk chemical intermediates. In mid-decade, when U.S. natural gas prices were significantly higher than other regions, and the Middle East was adding significant new bulk chemicals manufacturing capacity, U.S. chemical manufacturers increasingly focused on value-added specialty chemicals, exemplified by the "asset-light" strategy reported by Dow Chemical Company.[13] The closer integration of bulk chemicals manufacturing with value-added specialty chemical products, combined with lower U.S. natural gas prices, improves the market stability of the current domestic bulk chemicals manufacturing base.

Thus, our analysis indicates that current oil/natural gas price differentials favor the use of NGLs, where technologically feasible, as feedstock for U.S. ethylene production. While we were not able to perform a full analysis of potential changes in the global market for olefins, we identified several factors, including potential shift of ethylene cracking capacity, increased U.S. demand for polyethylene, and closer integration of bulk chemicals and value-added specialty chemicals that could increase domestic demand for NGLs.

### Changes in the NGL Supply Base

NGLs are mainly produced as a co-product from natural gas production. The amount of NGLs that is extracted from raw natural gas production depends upon the NGL content of the natural gas and the extent of NGL recovery before the gas is placed into pipelines. Product specifications set by interstate natural gas pipelines limit the NGL content in natural gas as entering the pipeline system, setting an upper limit of NGL content that can remain in natural gas. Natural gas processors have an economic incentive to recover more of the NGL content if the price for the NGLs (principally ethane), net of the cost of NGL recovery, is higher than the value of leaving the ethane in the gas stream.

There are several technologies for recovery of NGLs from natural gas. Absorption technology has been used extensively in the past to recover the heavier hydrocarbons, while newer cryogenic technology is the preferred approach to recover the lighter hydrocarbons. Broader application of cryogenic processing, which increases the yield of ethane recovered from raw natural gas, has caused the average ethane content of NGLs to increase from about 38% to 42%.[14]

Gas processing technology offers producers the flexibility to quickly and easily modify the level of NGL recovery from natural gas production depending upon relative prices of ethane and natural gas. The NGL content of natural gas varies by resource area. Even though a particular natural gas resource is relatively "wet" (i.e., has a relatively high content of NGLs), that factor alone does not automatically lead to higher NGL production.

Domestic production of NGLs increased 24% over the 20-year period from 1980 to 2000, peaking at 710 million barrels. Production declined by 13% through 2005, and has since resumed an upward path, reaching 714 million barrels in 2009.[15] Texas accounts for about 40% of NGL production, and Oklahoma accounts for an additional 10%. Production from offshore Gulf of Mexico natural gas resources has declined by about 25% from 2004 to 2009, and now accounts for only about 9% of domestic NGL supply. The three areas experiencing significant increases in NGL production over the past five years are Texas, Colorado, and Wyoming.

The decline of NGL production from relatively "wet" offshore Gulf of Mexico natural gas resources has increased interest in onshore natural gas resources, including shale gas formations, that are relatively "wet." The NGL content of shale gas varies greatly by resource area: shale gas from the Haynesville, Fayetteville, and Woodford formations is relatively "dry," while shale gas from the Eagle Ford formation and the Southwest Pennsylvania portion of the Marcellus region is relatively "wet." Thus, there will be increased demand for NGLs from shale gas formations, such as the Eagle Ford and Marcellus, simply to compensate for declining production from conventional Gulf of Mexico resources.

An increased emphasis on NGL production from the Marcellus region would have significant implications for natural gas infrastructure. Currently, NGL processing capacity is concentrated around the Gulf Coast, and new capacity may need to be added in the Marcellus region. The magnitude of increased NGL production and processing in the Marcellus region also may require the construction of pipeline capacity to transport ethane to existing cracking facilities in the Gulf region. Pipelines to existing petrochemical complexes in the Midwest and the Canadian Great Lakes region are also possibilities. In addition, a study is underway to analyze the feasibility of constructing new ethylene cracking capacity in West Virginia near Marcellus resources.[16]

The current oil/natural gas price differentials, decline in Gulf of Mexico NGL production, and the potential for growth in NGL demand favor the production of natural gas resources that have a relatively high content of NGLs. To the extent that NGL production is increased in the Marcellus region, there also would be a need to expand infrastructure as well, which is discussed in Chapter 6.

## NOTES

[1]The Energy Information Administration recently began separate tracking of natural gas use for hydrogen production. See http://www.eia.doe.gov/oiaf.servicerpt/hydro/appendixc.html.

[2]http://www.eia.doe.gov/oiad/servicerpt/hydro/appendixc.html.

[3]P. Dufor and J. Glen, "Analyst, Investor, and Journalist Site Visit Houston," Air Liquide, December 18–20, 2005. http://www.airliquide.com/file/otherelement/pi/pdf-corporate/2005-12-19_houston_hydrogen_today59319.pdf.

[4]Maritime freight rates are from Potash Corporation, Overview of Nitrogen Markets. Prices of natural gas are from Natural Resources Canada, Review of 2007/2008 North American natural gas demand and from Potash Corporation, The N-P-K Outlook 2006 and from the 2009 Q1 Market Analysis. Some of these prices are further quotes from Fertecon, a consultancy specialized in fertilizer markets. Manufacturing costs are from the Kirk-Othmer Encyclopedia of Chemical Technology. Average plant efficiencies are adapted from a study by the Canadian Industry Program for Energy Conservation: Benchmarking Energy Efficiency and Carbon Dioxide Emissions.

[5]This table is based on MIT analysis drawn from several data sources, including "Impact of Rising Natural Gas Prices on U.S. Ammonia Supply," and U.S. Department of Agriculture, Report WRS-0703, August 2007.

[6]"Petrochemicals: North American Firms are Pleasantly Surprised by a Robust Market," Chemical and Engineering News, January 24, 2011.

[7]Ibid.

[8]"2010 Polyethylene Annual Report," Townsend Solutions, August 2010, as cited at http://www.plasticmarketdata.com.

[9]A Morgan Stanley Blue Paper, "Petrochemicals: Preparing for a Supercycle," indicates that, except for Qatar, there will be slowdown in the pace of new capacity additions in the Middle East, resulting in "few 'feedstock-advantaged' new facilities during the next 3–4 years and the majority of new capacity will sit high on the cost curve."

[10]For, example, the American Chemistry Council reported that the U.S. trade deficit in plastic products was increasing, particularly in packaging, while U.S. exports of bulk chemicals, including polyethylene, polypropylene, polystyrene, and polyvinyl chloride resins increased. www.americanchemistry.org, "In Wake of Global Recession, U.S. Plastics Industry Struggled to Regain Ground During 2009."

[11]"Cheap Raw Materials and a Muted Industry Downturn Add Up to Good Times for U.S. Companies," Alexander H. Tullo, Chemical & Engineering News, March 7, 2011, pp. 22-25.

[12]"Petrochemicals' U.S. Growth Spurt," Alexander H. Tullo, Chemical & Engineering News, April 4, 2011, p. 12.

[13]"Chemicals Industry Refines its Strategy," www.IndustryWeek.com, February 2011.

[14]The two methods to recover NGLs from raw natural gas are the absorption process and the cryogenic process. Estimates of NGL product slate yields are from Morgan Stanley Research, Energy and Chemicals, October 7, 2010.

[15]U.S. Energy Information Administration, http://eia.gov/dnav/ng_prod_ngpl_sl_a.htm.

[16]Chemical & Engineering News, March 7, 2011, pp. 22–25.

# Appendix 5C: Commercial and Residential Applications of Combined Heat and Power

CHP systems, deployed at or near the point of application (i.e., distributed generation) have many attractive features. Thermal power plants generally have efficiencies in the 30% to 50% range, while CHP systems can operate in the 60% to 90% range by both producing electricity and capturing the residual heat to produce steam, hot water, and/or chilled water. The higher system efficiency suggests an opportunity to lower both costs and emissions. In addition, distributed generation can lower T&D losses; alleviate transmission bottlenecks and increase system reliability; reduce peak utility demand; and potentially eliminate or defer the need for T&D capital investment.

There are a number of different types of natural gas-fired CHP technologies available for commercial and residential applications. These technologies include fuel cells, micro turbines; and reciprocating engines (such as the Stirling engine). Fuel cells are based on electrochemical conversion of the hydrogen content of natural gas into electricity, water, and heat; the other technologies rely on natural gas combustion to generate electricity and heat. A principal metric for comparing alternative CHP technologies is the HPR. The HPR is the proportion of heat output per unit of electrical output from the CHP generator. A comparison of performance cost and key technical specifications for various CHP technologies is summarized in Table 5C.1.

One of the main challenges in the deployment of CHP systems is the optimal matching of CHP heat and power output to electricity and heat loads. This becomes increasingly critical at smaller-scale applications if the CHP system is not suitable for the type of load being served. For example, a household in New England has dramatically different heat/power needs in the summer and in the winter. Another challenge is the need for supplementary systems for power or heat to meet loads above the level of the CHP capacity and also to provide backup capability to cover maintenance and interruptions. For smaller applications, there can be substantial regulatory barriers and utility requirements to permit grid hookup.[1] Finally, bringing the power source close to the end use brings with it emissions and noise.

CHP systems for industrial applications are discussed in the industrial natural gas use section. In this appendix, we present two case studies for large (MW-e scale) commercial and small (kW-e scale) residential applications. These case studies illustrate the increased complexity involved in analyzing the feasibility of CHP for specific applications.

### Case Study of Commercial Scale CHP Application: MIT Campus

A case study for a CHP system in a large institutional setting is provided by the MIT campus CHP project. The project has been in operation for over 15 years, providing useful perspective on the economic, environmental, and regulatory issues affecting deployment of CHP systems.

**Table 5C.1 Performance and Cost Characteristics for Commercial CHP Technologies**

| | Fuel Cell [i] | Gas Turbine [ii] | Microturbine [iii] | Reciprocating Engine [iv] | Stirling Engine [v] |
|---|---|---|---|---|---|
| Size Range (kW-e) | 1.0–2,800 | 1,200–30,000 | 30–1,000 | 1.2–22,500 | 1.0–9.0 |
| Heat to Power Ratio (HPR) [vi] | 2.0–0.5 | 2.0–1.0 | 2.5–1.3 | 2.0–1.0 | 6.5–2.7 |
| Total Efficiency (LHV) [vii] | 50%–80% | 70%–80% | 70%–80% | 75%–80% | >85% |
| Electric Efficiency (LHV) | 25%–63% | 24%–38% | 25%–33% | 22%–47% | 10%–25% |
| Availability | >90% | >95% | 90%–98% | 91%–98% | NA |
| Part Load Performance or Efficiency | Excellent [viii] | Poor | Good [ix] | Good [x] | Good |
| Installed Cost ($/kW-e) [xi] | $7,700–$5,000 | $3,300–$1,100 | $3,000–$2,400 | $2,200–$1,100 | $9,000 |
| O&M Cost ($/kWh) [xii] | $0.086–$0.032 | $0.01–$0.004 | $0.025–$0.012 | $0.022–$0.009 | NA |
| Footprint (ft$^2$/kW-e) [xiii] | 2.0–0.5 | 0.15–0.04 | 0.42–0.18 | 0.47–0.062 | 6.5–3.0 |
| Noise (db) [xiv] | Moderate | Moderate | Moderate | High | Low |
| NOx (lb/MWh-e) | 0.01–0.07 | 2.40–0.60 | 0.54–0.14 | 0.10–2.43 | Low |
| Applications for Heat Recovery | Hot Water; LP-HP Steam | Hot Water; LP-HP Steam; Heat | Hot Water; LP Steam; Space Heating; Cooling | Hot Water; LP Steam; Space Heating | Hot Water; Space Heating |
| Useable Temp (ºF) | 150º–700ºF | 850º–950ºF | 470º–600ºF | 1,060º–700ºF | NA |

Source: EPA Catalog of CHP Technologies; Manufacturer data sheets.

Notes on Table 5C.1

[i] Performance characteristics are based on the UTC PC25 (PAFC), Fuel Cell Energy DFC 300MA (MCFC), Fuel Cell Energy DFC 1500MA (MCFC), Bloom Energy ES-500 (SOFC), Fuel Cell Energy DFC 3000 (MCFC), Ballard FC gen 1030 (PEM), Hexis Galileo 1000 N, Ceramic Fuel Cells BlueGen, Acumentrics AHEAD, Ceres Power, Topsoe, Ballard FCgen-1030V3, Baxi Innotech Gamma 1.0, Panasonic, IRD Gamma, and Dantherm Power. Cost numbers are based on the first four models.

[ii] Performance characteristics and costs are based on the Solar Turbines Saturn 20, Solar Turbines Taurus 60, Solar Turbines Mars 100, and GE LM2500+.

[iii] Performance characteristics are based on the Capstone C30, Capstone C65, Ingersoll Rand Power MT250, and Capstone C1000. Cost numbers are based on the first three models.

[iv] Performance characteristics are based on the GE Jenbacher JMS 312 GS-N.L., Caterpillar G3616 LE, Wartsila 5238 LN, Wartsila 46 20 V46, Baxi-SenerTec Dachs G5.5/G5.0, Honda Freewatt, Ecopower ecoPower e4.7/e3.0, Yanmar CP5VB/ENER.G4Y/ENER.G10Y, and EC Power. Cost numbers are based on the first four models.

[v] Performance characteristics are based on the WhisperGen MkV, Baxi Ecogen, Remeha, Enatec, Cleanergy CHP V161, Sunmachine Pellet, Disenco HPP, and Stirling Systems SEM. Cost numbers are based on WhisperGen trial units through UK distributor.

[vi] Heat-to-Power Ratio = Useful steam output (Btu) / CHP electrical power output (Btu).

[vii] CHP Efficiency = (net electricity generated + net steam produced for thermal needs) / total system fuel input.

[viii] The efficiency at 40% load is within 2% of its full load efficiency.

[ix] 80% normalized efficiency at 43% load.

[x] 90% of full load efficiency at 50% load, the curve gets steeper afterwards.

[xi] Cost numbers are derived from the EPA Catalog of CHP Technologies with the exception of the Stirling engine. Installed and O&M costs are cited in 2007 dollars.

[xii] O&M costs vary according to fuel type and service.

[xii] Footprint = Total Area (Fuel Cell Module + EBOP + MBOP) / Power Rating.

[xiv] Noise levels were classified into three levels: 1) low: less than 60db, 2) moderate: between 60db and 70db, 3) high: greater than 70db.

Initial planning for the project began in the 1980s. At that time, the project faced a number of regulatory barriers that stood in the way of licensing such projects.[2] Fortunately, some of these barriers have since been lowered dramatically in many parts of the country.

The CHP project was placed in service in 1995 with the expectation of reduced energy costs, improved quality of power, and reduced net atmospheric emissions. However, the benefits depend on external conditions, such as the electricity generation mix and natural gas prices, that can change over time.

The MIT CHP facility has four major components: a CGT, HRSG, chiller system, and supplementary boilers, with natural gas as the primary fuel for the CGT and boilers. The CGT unit has an electrical capacity of 21 MW-e nominal, where the waste heat of the exhaust gas of the turbine is used by the HRSG to generate steam. Additionally, the campus is connected to the local electric distribution utility for supplemental electric power and for backup power in case of outages. The CGT has provided over 75% of the electricity load, historically with an electric efficiency of around 26%. In 2010, the plant generated about 204 GWh, which represented almost 72% of the Institute's electrical needs. The steam load was mostly provided by the HRSG system, while the boilers supplied the rest of the total steam consumption (especially used during peak hours, winter and at times when the CGT was under maintenance).

We analyzed the MIT CHP project in the context of current and projected market and regulatory conditions with the goal of understanding the economic viability of such a CHP project today. We compared the cost of the CHP project (CHP case) to a reference case that combined purchasing electricity from the local utility, using its mix of fuels, and generating steam on campus with boilers. Values for natural gas and fuel oil were taken from the EIA's price projections contained in 2010 Annual Energy Outlook. Electricity prices were taken from the local utility tariff rates for the year 2010, with price projections assumed to follow the natural gas prices. Operational costs include the costs incurred in operation & maintenance (O&M), electric power purchase (supplemental, maintenance, and emergency) and fuel purchase. In addition to the operational costs, we included the capital carrying costs of the cogeneration project, which had an initial investment cost of about $50 million.

With these assumptions, we estimated the present value of the annual operational costs and the cumulative $CO_2$ emissions for the period 2011 to 2025 for both the CHP and reference cases. The results show a present value (at a 7.125% discount rate) cost of $156 million for the reference case. The estimated present value cost of the CHP case (including the financing costs) is $128 million, representing about 20% cost savings. $CO_2$ emissions in the CHP case are lower by a total of 0.73 million metric tons over the 15-year period. This represents about a 17% emissions reduction relative to the reference case fuel mix, where about half of utility generation is carbon-free, a third from natural gas, and the remaining from oil and coal-fired technologies (i.e., a relatively carbon light mix compared with the U.S. average). Table 5C.2 provides an overall summary of these results.

Although our results show that a CHP system provides significant economic and environmental benefits, changes in market and regulatory conditions (such as access charges for the grid connection) can greatly affect the benefits and viability of CHP projects. Higher natural gas prices would reduce the benefits and

**Table 5C.2 Impacts of CHP Deployment on the MIT Campus**

| Results period 2011–2025 | | Reference case | CHP case |
|---|---|---|---|
| **Total electric energy** | | | |
| Purchase | GWh | 3,867 | 1,554 |
| Self-generation | GWh | 0 | 2,313 |
| **Total fuel purchase** | | | |
| Natural Gas | MMBtu | 3,474,639 | 38,325,000 |
| Oil | MMBtu | 34,068,052 | 12,307,112 |
| **Total $CO_2$ emissions** | **tons (000)** | **4,325** | **3,592** |
| From electricity purchase | tons (000) | 1,465 | 589 |
| From fuel | tons (000) | 2,860 | 3,003 |
| $CO_2$ savings | tons (000) | — | 733 |
| **Operational costs** | **$ millions** | **571** | **414** |
| Savings | $ millions | — | 157 |
| **Investment cost** | **$ millions** | — | **49** |
| **NPV project** | **$ millions** | — | **128** |

Source: Tapia-Ahumada (2005)

perhaps even make the CHP project uneconomic (depending on the utility fuel mix). On the other hand, a $CO_2$ emissions price would add to the economic advantage. In the MIT example, with the New England utility fuel mix, CHP reduces $CO_2$ emissions by 48,000 tons/yr. A $27/ton $CO_2$ price would bring additional economic savings with a present value of about $13 million.

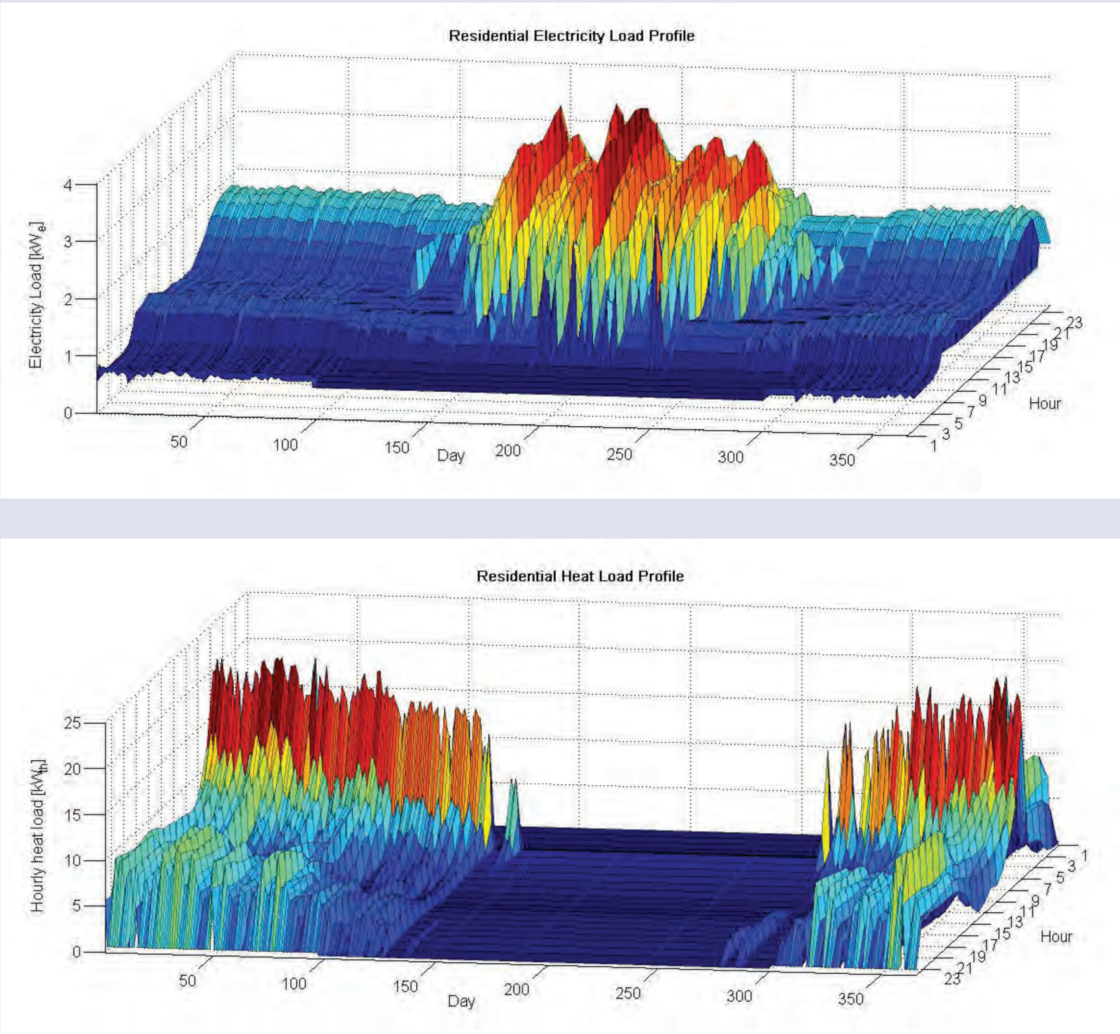
In summary, this case study is indicative of substantial economic and environmental benefits that will accrue to fairly large CHP systems under anticipated market conditions, with even larger benefits when $CO_2$ emissions are priced. This supports the notion of public policies that remove regulatory barriers to implementation of such systems and, in the absence of a carbon charge, that incentivize larger-scale deployment.

### Case Study of Residential Application of Micro-CHP Systems

For the case of micro-CHP (i.e., kW-e scale) installations, mostly targeted to residential customers, the potential economic and environmental benefits depend not only on the incremental capital cost with respect to conventional sources of heat and power, but also on the suitability of the technology to meet residential energy load, especially when on-site thermal and electricity needs may not be correlated (and matching the micro-CHP outputs to the customer requirements may be challenging).

We analyze the case of an individual customer located in New England, focusing on the operation and performance of a particular micro-CHP system over a one-year time period. For purposes of determining electricity and heat loads for a medium-size home located in the Boston area, we simulated the energy profiles for every hour of the year using Energy-10™ (version 1.8) software, developed by the National Renewable Energy Laboratory's Center for Building and Thermal Systems. Figure 5C.1 summarizes the simulated energy load profiles,[3] illustrating the considerable divergence between heating and electricity loads.

**Figure 5C.1 Hourly Electric and Heat Demands for a Year, Based on Energy-10™ Simulations for Boston, in kWh**




Source: Tapia-Ahumada (2011)

These figures highlight significant seasonal and time-of-day variations:

- The *electric load profile* shows increased demand for electricity during summer because of the use of air-conditioning which is operated between 7:00 am until 11:00 pm, with peak consumption between 5:00 pm and 6:00 pm. During winter, the electric load is in general quite flat with some minor increments after 5:00 pm because of the occupancy in the house and the blower fan used to distribute warm air throughout the dwelling; and

- The *heat load profile* shows that the heating requirement is highest during winter because of the central heating system being used during the day with a peak at around 7:00 am when the thermostat is activated after the night setback. Once the house has reached the required temperature, the heating devices maintain the temperature during the day. In summer the heat load is much lower since there is no need for space heating. However, heat is still required during the day for servicing hot water use, primarily in the morning and evening.

These load profiles are met with the use of an engine-based micro-CHP technology[4] with an electric efficiency of about 24%, three engine speeds producing electric outputs of 1.37, 2.37 and 4.70 kW-e, and a hot water heating application. We assume rapid changes between the various operating levels. The system is supplemented by a high-efficiency boiler (95%) for peaking thermal demand, in particular during winter. The HPR of the micro-CHP has a median value of about 3.0. Different CHP technologies will have different HPR and they may be more or less suitable to match on-site demand.[5]

Our analysis uses energy prices based on actual local utility rates and utility fuel mix. We also assume that excess electricity generation from the micro-CHP system is sold back to the local utility at a rate equal to 1 cent/kWh-e below the retail price being charged to the customer.

We analyzed two possible operating strategies for the micro-CHPs: 1) heat-led operation, where the micro-CHP system operates to meet on-site heat load and any excess of electricity is fed back into the utility grid; and 2) electricity-led operation, where the micro-CHP system operates to meet on-site electric load and excess of heat is either stored or dumped outdoors.

The results for the *heat-led operating strategy* show net efficiency benefit of 16% and $CO_2$ emissions reductions of 19% relative to the reference no-CHP case. Also, the heat-led operation leads to a 15% annual energy cost savings, with savings accruing mostly during the winter season because of the full utilization of produced heat and the reduced utility electricity requirements.

The results for an *electricity-led operating strategy* show no net benefit for micro-CHP. Annual energy costs and $CO_2$ emissions are increased, because the produced heat does not coincide with the heat load, leading to considerable excess of heat during summer (while producing electricity at a relatively low efficiency).

The comparison of the results for the two operating strategies emphasize the point that the large differences between heating and electricity loads requires close matching with micro-CHP heat and power output.

We also considered the effect of different types of micro-CHP systems with different HPR values. The results favor the deployment of micro-CHPs with lower HPR values, because the heat following operating mode enables electricity savings to increase with heating requirements. Micro-CHP systems with very high HPR (such as Stirling engine systems) do not appear to be a competitive alternative because they generate little electricity per every unit of produced heat, so the potential savings from displaced electricity are relatively small. This result indicates that, if capital costs reductions can be realized, fuel cell-based micro-CHP systems (typically with low HPR) could be attractive for future energy systems because of a more consistent operation, and better economic and environmental results.

Currently, micro-CHP systems have high investment costs, a factor that has been recognized as one of the main reasons for the slow deployment of such systems. Our analysis shows that the savings in heating and electricity costs are not sufficient to support payback of the initial capital investment within any reasonable time frame, making investments in micro-CHP unattractive to consumers. However, as the technology matures and becomes commercially available (as in the case of some gas-based engine technologies), it is expected that capital costs will decrease with greater production and experience. Sensitivity analyses show, for example, that for this particular residential case study, the capital cost needs to decrease (by at least 35% from the reference case[6]) and the electrical output should be close to 1 kW (with a capacity factor over 70%) for the payback period to be reduced to 8 to 9 years.

Public policy incentives have a significant interplay with the attractiveness of micro-CHP systems. Micro-CHP technologies with low HPR are clearly helped by policies that require utilities to buy back excess generation, possibly reflecting real-time pricing. This can have system benefits in reducing peak utility loads, particularly in summer. However, such policies could lead to unintended consequences, if the micro-CHP is operated during periods when there is no heat load, thereby decreasing the overall efficiency and emissions performance of the micro-CHP system. Policy incentives (such as buyback rates, loan guarantees, tax credits, and natural gas price discounts) clearly need careful design appropriate to the micro-CHP technology mix, the heat and electricity loads, and the regional utility fuel mix.

Large-scale adoption of residential micro-CHPs poses a variety of technical, economic, and regulatory challenges regarding their integration into centralized electric power systems (e.g., rules for utility interconnection charges and permitting processes, electricity rates). We examined the impacts of large-scale penetration of micro-CHPs within a large regional energy system, where micro-CHP deployment impacts the mix of generation capacity of the electric power portfolio as well as its operation.

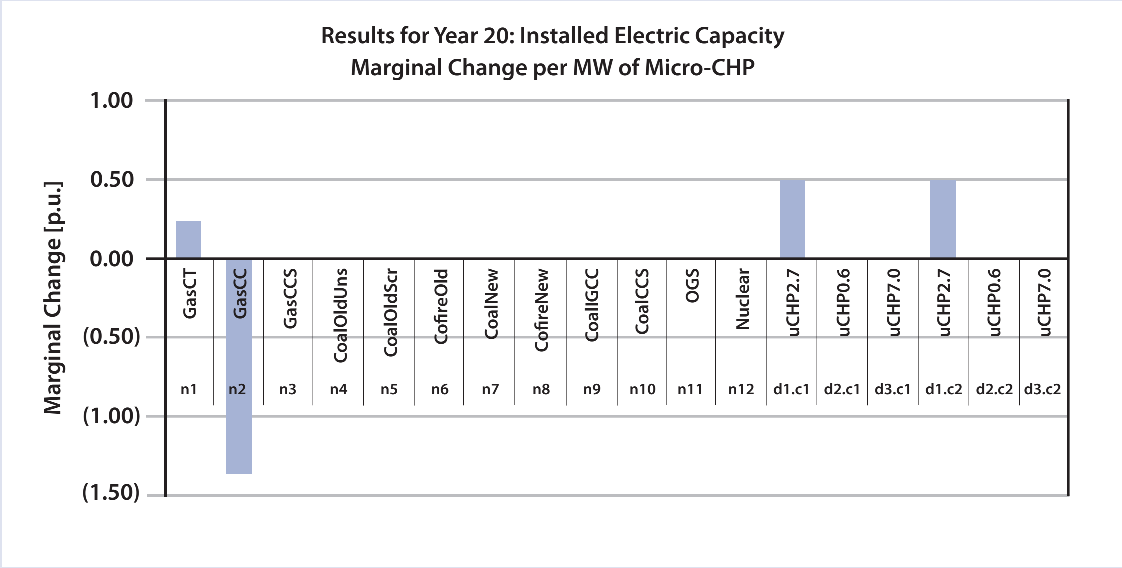
We projected the impact on central station generation resulting from micro-CHP deployment achieving a market penetration equivalent to 10% of the system electric installed capacity over a 20-year period. The system is loosely based on New England. The modeling analysis reflects assumptions favorable to micro-CHP deployment, i.e., a carbon price of \$98.74/ton and a 35% reduction in the capital cost of micro-CHP units relative to current estimates.[7]

Figure 5C.2 shows the changes in the technology mix of the system for an additional unit (+1 MW) of micro-CHP installed capacity in year 2027. The deployment of micro-CHP displaces mostly natural gas combined cycle (NGCC) capacity, but requires additional natural gas turbine capacity for backup purposes.

Figure 5C.3 shows that micro-CHP generation displaces NGCC generation almost exclusively. Additional generation from gas turbines is very small. During summer, as the heat demand is low, the operation of micro-CHPs is more irregular (and sometimes sensitive to high electricity prices). This behavior requires the combustion turbines occasionally to take up the slack in load matching resulting from the decreased NGCC capacity.

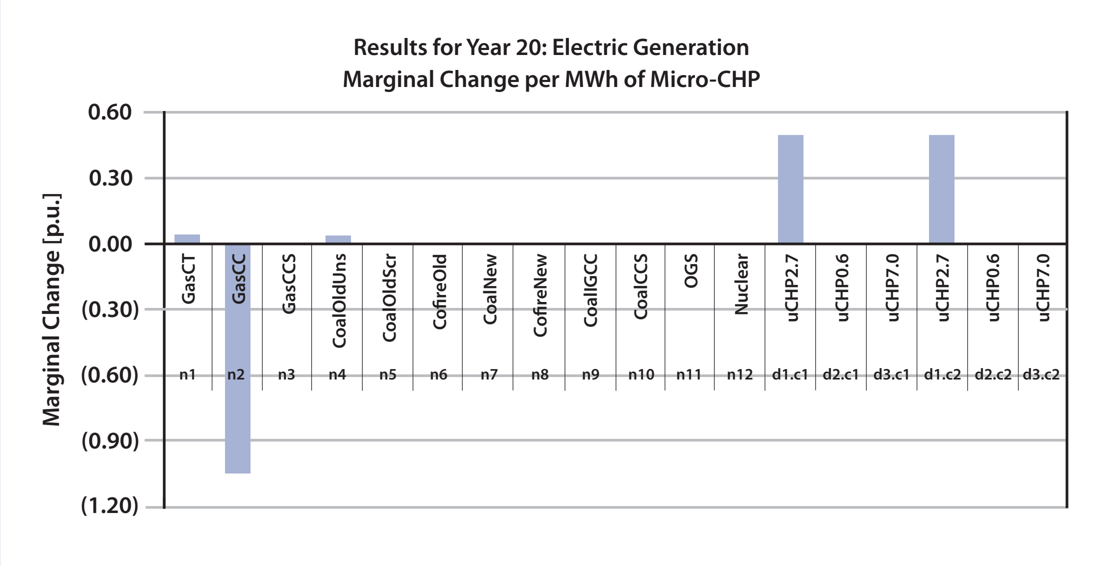
We estimated that the micro-CHP penetration would reduce cumulative total system-wide $CO_2$ emissions by 4% to 5% over a 20-year time period — considering emissions coming from the production of electricity and heat. The $CO_2$ emission reductions decrease over time because the carbon price induces changes in the electric system generation portfolio to one with lower carbon content than at the start of the study.

**Figure 5C.2 Installed Capacity Marginal Change for +1 MW of Micro-CHP: Micro-CHP vs. No Micro-CHP Cases**




Source: Tapia-Ahumada (2011)

**Figure 5C.3 Electric Production Marginal Change +1 MWh of Micro-CHP: Micro-CHP vs. No Micro-CHP Cases**




Source: Tapia-Ahumada (2011)

## NOTES

[1]"Turning off the Heat," Thomas Casten, Prometheus Press, 1998.

[2]Tapia-Ahumada, Karen (2005), "Are Distributed Energy Technologies a Viable Alternative for Institutional Settings? Lessons from MIT Cogeneration Plant." M.Sc. Thesis, Engineering Systems Division, MIT: Cambridge, 2005.

[3]Tapia-Ahumada, Karen (2011), "Understanding the Impact of Large-Scale Penetration of Micro Combined Heat & Power Technologies within Energy Systems," PhD Thesis, Engineering Systems Division, MIT: Cambridge, 2011.

[4]Technology is loosely based on a product Ecopower Micro-CHP from Marathon Engine Systems.

[5]A micro-CHP with high HPR is a technology able to generate a significant amount of heat per every unit of electricity. Also, a high HPR value characterizes a technology with high thermal efficiency and low electric efficiency. Conversely, a low HPR characterizes a micro-CHP with low thermal efficiency and high electric efficiency.

[6]There is a great uncertainty around capital cost estimates for micro-CHP systems. Based on figures of some commercial units cited in (Tapia-Ahumada, 2011) we assume a reference value of 7,000/kW-e ($2007) for all technologies.

[7]A 35% micro-CHP capital cost reduction results in a cost of about 4,500/kW-e ($2007).

# Appendix 5D: Comparing Residential Space Conditioning and Hot Water Technologies and "Site Efficiencies"

Currently, there is significant competition between natural gas and electricity in the residential sector in space conditioning and for domestic hot water. In some applications, and in some regions, home heating oil and liquid petroleum gas (LPG) are also used in addition to natural gas and electricity. These include boilers and furnaces for heating, air-conditioning systems and heat-pump systems that provide both heating and cooling. To provide hot water, there are storage tank systems (including some using heat pumps), and instantaneous (tankless) hot water heaters. Table 5D.1 provides an overview of the major types of heating, cooling, and hot water systems, a subset of which were discussed in Chapter 5.

**Table 5D.1 Major Types of Residential Space Conditioning and Hot Water Systems (Whole-House Systems)**

| Space Heating Only |
|---|
| **Furnaces:** Furnaces generally heat air which is then circulated throughout a home via ductwork, including an air return system. Natural gas is the most common fuel for such systems, although LPG and heating oil systems can be found. In regions where it does not get very cold, electric systems are also common where an electric resistance heating coil or duct heater is integrated into the home's air handling system. It is important to include the electricity used to move the air in such systems when looking at their efficiency, and not just the energy used to heat the air. |
| **Boilers:** Boilers commonly heat water instead of air, and are fueled almost exclusively by natural gas or home heating oil. Hot water or steam circulates in the home in pipes, and heats the air via radiators or pipe systems in the floor (radiant heating). Some systems use the thermal buoyancy of the hot water or steam to circulate the heat within the house, while other systems require pumps. |
| **Baseboard Heat:** Some homes use direct electric resistance heating within a home's rooms (baseboard electric heat). This is especially common for small homes (or additions to existing homes) without a centralized duct system. |
| **Space Cooling Only** |
| Air conditioners both cool and dehumidify air. Most "centralized" air conditioners are split systems where the refrigerant is circulated through a compressor external to the house, and the returning cold water reduces the temperature of the air in a cooling coil within a house's duct work. For dehumidification, the air is cooled below the dew point, allowing the water to condense where it is drained off. More efficient air-conditioning systems recapture the excess cold by pre-cooling incoming air. |
| **Combined Heating and Cooling** |
| Heat pumps can deliver either heat or cold to the interior of a building. In cooling mode, they operate exactly like an air conditioner. Air conditioners deliver cold air to the inside of the house, and reject heat outside as the compressor squeezes the heat out of the refrigerant. Heat pumps have additional controls and valves so that, in heating mode, the heat can be sent to the house's heat exchanger as well. |
| **Air-Source Heat Pumps:** Most heat pumps use the air outside the house as the external temperature reservoir for heating and cooling. Like most central AC units, air-source heat pumps are split systems with the one heat exchanger (and compressor) outside the building, and the other inside. In regions where it gets much colder than freezing, the ability of air-source heat pumps to deliver sufficient heat is impaired, especially if the external heat exchanger develops frost or ice, and so sometimes they must be paired with a furnace, or substituted with a ground-source heat pump. |

**Table 5D.1 Major Types of Residential Space Conditioning and Hot Water Systems (Whole-House Systems)** continued

| |
|---|
| **Ground-Source (Geothermal) Heat Pumps (GSHP):** In regions where it gets too cold for air-source heat pumps, the heat of the earth can be used as the external temperature reservoir. This generally requires the installation of an additional circuit of pipes in the earth to reject or collect heat, where air-source heat pumps just use outside air. The variety of circuit types in the ground is quite large, and depends in part on the soil temperature and type, available area and, of course, overall system cost. Looser soils allow easy trenching for the installation of lateral (horizontal) coils of piping. Areas where there is a lot a rock, or not enough room for a horizontal coil, a vertical hole or well will be drilled and the ground-source loop placed within the well. These types of systems are called Closed Loop Ground-Source Heat Pumps.<br><br>In areas where there is abundant ground water, or a lake or river adjacent to the building, an Open-Loop GSHP is another alternative where water is drawn from the aquifer or lake, circulated through the heat exchanger and then reinjected into another area of the aquifer or lake. In some instances where the temperature of the water or ground is close to that needed for heating or cooling, a "direct exchange" GSHP can be installed; during times of near-equal temperature only the heat exchanger and not the refrigeration system is used, further reducing energy use. |
| **Water Heaters** |
| **Storage Hot Water Systems:** Most hot water heaters use natural gas, LPG or electricity to heat water which is then stored in a tank. This allows for smaller, lower power burners or heating coils to provide sufficient hot water when there are multiple end-uses (bathrooms, kitchen and other uses). Electric heat-pump hot water heaters have entered the market in recent years. These systems use the temperature of the house (or basement) as the heat pump's "external" temperature reservoir much like a refrigerator. Due to the amount of energy the systems are asked to deliver (in comparison to a refrigerator/freezer), household room temperature impacts may need to be taken into account. |
| **Instantaneous/Tankless Hot Water Systems:** The duty-cycle of residential hot water heaters for the modern family means that they often sit idle for large portions of the day. For applications where hot water demands are low and/or infrequent, instantaneous hot water systems are an alternative. In these applications electricity, natural gas or LPG is used to heat the stream of water as it passes directly on its way to the kitchen or bathroom. These systems need a little more time to "warm up" compared to tank storage systems, and cannot serve several users simultaneously. |

The above list focuses on whole-house systems, although there are also window unit and portable split-system air conditioners, as well as portable electric and kerosene heaters, and wood stoves.

To compare these diverse technologies a common metric for energy efficiency was used in this report: the "Seasonal Co-efficient of Performance" (SCOP), which is defined as the ratio of the useful heating or cooling delivered, divided by the amount of retail energy consumed. Note that the SCOP is not the efficiency metrics used by equipment manufacturers. Table 5D.2 shows the diversity of efficiency metrics used in industry. Some of these are direct ratios of energy consumption; however, some of them mix heat (Btu) and electric (watt-hour) units, sometimes for the same device. Most are provided as "seasonal average efficiencies," although not all.

A "Co-efficient of Performance" (COP) is a term often used instead of utilization efficiency or another similar name when the "efficiency" can be greater than one. In air-conditioning and heat-pump systems, the electricity is not used directly for heat (as it is in electric resistance applications) but instead leverages inside and outside temperatures moving the heat, e.g., from the inside to the outside as in the case of an air conditioner. This moving of energy, instead of its direct consumption, allows for much-improved ratios of retail energy consumed to heating or cooling delivered, and hence efficiency.

For most of the heating and cooling systems, the efficiency metric is stated as an annual average for a reference heating or cooling season, although how this reference winter or summer compares to a consumer's actual situation is usually unknown. GSHP COPs lack this seasonal adjustment since there is no good average ground temperature baseline to use. Measured instead at their optimal performance point, GSHP COPs are usually higher than the SCOPs of air-source heat pumps or air conditioners.

**Table 5D.2 Common Energy Efficiency Metrics for Major Space Conditioning Systems**

| Acronym | Efficiency Metric Name / Definition | (efficiency metric units) |
|---|---|---|
| **Application** | | |
| Technology Type | | |
| **Acronym** | **Efficiency Metric Name**<br>Definition | (efficiency metric units) |
| **Space Heating (Whole-House Systems)** | | |
| Furnaces and Boilers | | |
| **AFUE** | **Annual Fuel Utilization Efficiency**<br>Ratio of energy delivered to retail energy consumed | (% or Ratio – seasonal average) |
| Air-Source Heat Pumps | | |
| **HSPF** | **Heating Seasonal Performance Factor**<br>Btu of energy delivered per watt-hour of electricity consumed | (Btu/watt-hour – seasonal average) |
| Ground-Source (Geothermal) Heat Pumps | | |
| **COP** | **Co-efficient of Performance**<br>Ratio of energy delivered to retail energy consumed | (% or Ratio – test conditions, not seasonal) |
| **Space Cooling and Dehumidification (Whole-House Systems)** | | |
| Air Conditioners | | |
| **SEER** | **Seasonal Energy Efficiency Ratio**<br>Btu of energy delivered per watt-hour of electricity consumed | (Btu/watt-hour – seasonal average) |
| Air-Source Heat Pumps | | |
| **SEER** | **Seasonal Energy Efficiency Ratio**<br>Btu of energy delivered per watt-hour of electricity consumed | (Btu/watt-hour – seasonal average) |
| Ground-Source (Geothermal) Heat Pumps | | |
| **EER** | **Energy Efficiency Ratio**<br>Ratio of energy delivered to retail energy consumed | (Btu/watt-hour – test conditions, not seasonal) |
| **Hot Water Systems** | | |
| All Types – Gas, Oil, Propane and Electric Resistance and Heat-Pump Systems – Storage and Instantaneous | | |
| **EF** | **Energy Factor**<br>Ratio of energy delivered to retail energy consumed | (% or Ratio) |

Table 5D.3 shows the AFUEs, HSPFs, COPs, SEERs, EERs, and EFs for the most common type of systems, and the equivalent SCOPs excerpted for the main body of the report. Note that these are end-use or "site efficiencies" and do not include the energy losses from fuel production, transport, and distribution, nor the losses associated with the generation of electricity that are presented and discussed at length in Chapter 5.

**Table 5D.3 Site Energy Efficiencies for Common Space Conditioning and Hot Water Systems[1]**

| | Appliance/Systems Efficiency | | | Site Energy Efficiency | | |
|---|---|---|---|---|---|---|
| | Low | Energy Star | Best | Low | Energy Star | Best |
| **Residential Heating Systems** | | | | | | |
| **Furnaces** | **AFUE** | | | **SCOP (same)** | | |
| Electric Furnaces | 0.95 | — | 0.99 | 0.95 | — | 0.99 |
| Oil-Fired Furnaces | 0.78 | 0.83 | 0.95 | 0.78 | 0.83 | 0.95 |
| Gas-Fired Furnaces | 0.78 | 0.90 | 0.98 | 0.78 | 0.90 | 0.98 |
| **Boilers** | **AFUE** | | | **SCOP (same)** | | |
| Oil-Fired | 0.80 | 0.85 | 0.95 | 0.80 | 0.85 | 0.95 |
| Gas-Fired | 0.80 | 0.95 | 0.98 | 0.80 | 0.95 | 0.98 |
| **Air-Source Heat Pumps** | **HSPF** | | | **SCOP** | | |
| Split Systems | 7.85 | 8.19 | 17.74 | 2.30 | 2.40 | 5.20 |
| **Ground-Source** | **COP** | | | **COP** | | |
| Closed Systems | 2.50 | 3.30 | 4.80 | 2.50 | 3.30 | 4.80 |
| Open Loop | — | 3.60 | 5.50 | — | 3.60 | 5.50 |
| Direct Exchange | — | 3.50 | 3.80 | — | 3.50 | 3.80 |
| **Residential Cooling Systems** | | | | | | |
| **Central Air-Conditioning** | **SEER** | | | **SCOP** | | |
| Split Systems | 13.00 | 14.50 | 23.00 | 3.81 | 4.25 | 6.74 |
| **Air-Source Heat Pumps** | **SEER** | | | **SCOP** | | |
| Split Systems | 13.00 | 14.50 | 17.00 | 3.81 | 4.25 | 4.98 |
| **Ground-Source** | **EER** | | | **COP** | | |
| Closed Systems | 8.70 | 14.10 | 22.40 | 2.55 | 4.13 | 6.57 |
| Open Loop | — | 16.20 | 30.00 | — | 4.75 | 8.79 |
| Direct Exchange | — | 15.00 | 23.80 | — | 4.40 | 6.98 |
| **Residential Hot Water Systems** | | | | | | |
| **Storage Systems** | **EF** | | | **SCOP (same)** | | |
| Electric | 0.92 | — | 0.95 | 0.92 | — | 0.95 |
| Electric Heat Pump | — | 2.00 | 2.35 | — | 2.00 | 2.35 |
| Oil | 0.51 | — | 0.68 | 0.51 | — | 0.68 |
| Natural Gas | 0.59 | 0.62 | 0.70 | 0.59 | 0.62 | 0.70 |
| **Tankless-Instantaneous** | **EF** | | | **SCOP (same)** | | |
| Electric | 0.93 | — | 0.99 | 0.93 | — | 0.99 |
| Natural Gas | 0.54 | 0.82 | 0.94 | 0.54 | 0.82 | 0.94 |

## NOTES

[1]Compiled from a variety of sources including the US DOE, EnergyStar, ACEEE, AHRI, and others.

# Appendix 8A: Natural Gas RD&D Background

This appendix provides information supplementary to that in Chapter 8 regarding: industry and DOE support of natural gas RD&D; the impacts on natural gas RD&D of industry and regulatory structures; and public-private partnerships.

### Industry RD&D

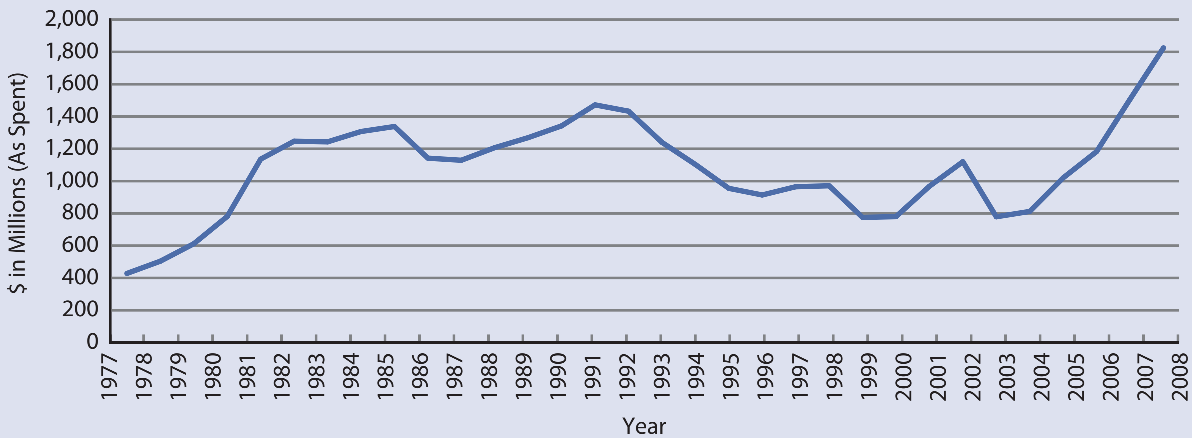
The U.S. Government Accountability Office (GAO) estimates that the natural gas and oil supply industry, including operators and service companies, spent around $20 billion ($9.6 billion by operators, $10.7 billion by service companies) on research in the decade between 1997 and 2006.[1] The longer-term trends in oil and gas R&D-related spending by the major petroleum companies are shown in Figure 8A.1[2] below. In 2008, the major oil and gas companies allocated $1.8 billion to oil and gas R&D. The industry-reported R&D spending data do not provide much detail on research priorities, but indications are that the company-funded oil and gas R&D was focused on production and processing issues. As noted by the GAO, this research has tended to be short-term in nature, with a 2-to-3-year time horizon and an understandable goal of enhancing the scale and value of corporate reserves.

The supply research, including the research contracted with service companies, has had a major component focused on offshore exploration and production. This focus reflects the fact that the oil and gas industry in the U.S. is mature and has increasingly moved offshore. Development of unconventional natural gas resources was left for the most part to small and independent producers that historically have very small RD&D budgets. Consequently, the technology foundations for today's important unconventional gas production was established through strong direct and indirect public engagement, as discussed below.

### Federal Support of Natural Gas RD&D

The Department of Energy (DOE) is the primary U.S. government sponsor of energy technology RD&D. It has supported several natural gas technology programs since its inception in 1977, spending slightly more than $1 billion (in current dollars) on these programs between 1978 and 2010. A summary of the major DOE natural gas RD&D programs in the Office of Fossil Energy, including total funding levels, is seen in Table 8A.1.[3]

**Figure 8A.1 Industry Petroleum and Natural Gas R&D Spending**




Source: EIA

**Table 8A.1 DOE Natural Gas RD&D Program Overview**[4]

| Program | Total, $M | Duration | Program Description |
|---|---|---|---|
| Natural Gas Program, Total | 1,076.2 | | |
| Subtotal, UNG Research[5] | 312.4 | | |
| Coal Bed Methane (CBM) | 15.7 | 1978–1982 | Focused on assessing the size and the recoverability of the CBM resource |
| Eastern Gas Shales | 84.2 | 1978–1992 | Focused on the basic science of the resource as well as assessing the size of the resource base |
| Western Gas Shales | 95.3 | 1978–1992[6] | Focused on characterizing the low permeability reservoirs and establishing reservoir properties |
| Methane Hydrates | 114.6 | 2000–2010 | Conducted basic research to understand the fundamental characteristics of the resource |
| Environmental Research[7] | 103.4 | 1978–2006, 2008–2010 | Technology development for low-impact exploration, production, processing, transportation, and storage |
| Exploration and Production | 240.9 | 1993–2006 | Development of more cost-effective, more efficient drilling, completion and stimulation techniques |
| Infrastructure | 51.8 | 1994–2005 | Focused on improving the reliability and deliverability of storage and gas transmission and distribution networks |
| Utilization/Emerging Process Technologies | 64.8 | 1993–2003 | Assessment of different conversion technologies such as remote gas-to-liquids conversion and producing hydrogen from gas |
| Advanced Turbine Systems | 294.5 | 1992–2001 | Development of high-temperature gas turbines that achieved NGCC efficiencies of 60% and single-digit NOx emissions |

The early DOE natural gas supply program, born out of concerns raised by the Arab oil embargoes, focused on the development of unconventional natural gas. More specifically:

- *Coal Bed Methane:* the DOE program was funded from 1978 to 1982. The program can be credited for defining the size and the recoverability of the resource base as well as laying the basic knowledge foundation.

- *Tight Gas:* the DOE established the Western Gas Sands program in 1978. The program ended in 1992, but some of its activities were moved to the exploration and production program established in 1993. Its major accomplishment was resource characterization, developing tools and procedures to measure tight rock properties and predictive geologic models.

- *Shale Gas:* The Energy Research and Development Administration (ERDA), DOE's predecessor agency, established the Eastern Gas Shales program in 1976. The program was assumed by the DOE in 1978 and then terminated in 1992. It can be credited for the expansion of knowledge on natural fracture networks.

However, the scale of the funding and the focus on resource characterization, while important, were not commensurate with development of the technology base for unconventional resource production. A public-private partnership enabled by the regulated nature of the industry filled the gap (discussed below).

Following the early work on unconventional resource characterization, Federal funding for natural gas RD&D fell to very low levels, before rebounding in the 1990s with a different focus. Two programs are of note. For supply, a program on natural gas hydrates was established. This program is focused on basic research and resource characterization. For natural gas utilization, the goal was increased efficiency of natural gas use in electricity generation, prompted by repeal of the Fuel Use Act, low gas prices in the early-to-mid 1990s, the development of NGCCs, and the environmental desirability of natural gas. The principal DOE response was establishment of a partnership with industry called the Advanced Turbine Systems program. The goal was a substantially increased operating temperature that enables higher efficiency. This has been achieved so that these advanced turbines are now available in the marketplace for next generation plants. See Appendix 8.2.

### Regulation and RD&D

The Federal Energy Regulatory Commission (FERC) has specific authorities to enable funding of industry R&D focused on the needs of the natural gas consumer. FERC chose to exercise this optional authority through the Gas Research Institute (GRI), a private non-profit research management organization formed in 1976 and funded through a FERC-sanctioned surcharge placed on interstate pipeline gas volumes. The surcharge was determined on an annual basis according to a 5-year comprehensive R&D plan submitted by GRI to FERC. The FERC-approved surcharge in 1978, for example, was equal to 0.12 cents per Mcf; in 1988, it was up to 1.51 cents per Mcf.

The Gas Research Institute's research portfolio was broad, spanning the gas value chain from production to end-use. It served as the research arm of the U.S. natural gas industry for over two decades and its surcharge-generated research funding became appreciable, exceeding $200 million/year for an extended period of time. Total R&D funding for GRI over the life of the surcharge was over $3 billion. In 1993, Burnett et al. concluded that GRI's 30% success rate in converting applied R&D projects into commercial products, process or techniques was twice as high as the industry average.[8]

In a regulated environment, this surcharge was easily passed on by the pipeline companies to ratepayers. After pipelines became common carriers in 1992, large gas consumers (e.g., major industrials) could contract directly with gas producers. In this new, more open marketplace, the FERC surcharge, while quite small per unit of gas, became a competitive issue as very large volumes of gas moved directly between producers and these consumers. As a result of "bottom line" pressures associated with more competitive markets, the tendency of state regulators to eschew rate increases in more competitive markets and a number of "free riders" (primarily intrastate pipelines in Texas which were not paying the surcharge), the surcharge was phased out over several years and discontinued in 2004.

The Gas Research Institute reorganized and, together with the Institute for Gas Technology, became the Gas Technology Institute (GTI) in 2000. However, GTI is a research performer, mostly for industry, without the GRI mission of serving natural gas consumers.[9]

While the natural gas supply and interstate transportation sectors of the industry have been deregulated, the distribution and end-use markets remain regulated. Natural gas distributors are subject to rate regulation by the states based on cost-of-service principles. Cost-of-service regulation does not provide market incentive for innovative efficient end-use technologies or demand reduction. Policy makers have sought to address this market failure through mandatory demand side management (DSM) requirements, including decoupling of profits from sales volume. However, as with cost-of-service regulation, decoupling still does not provide a strong incentive for R&D since its risks are high, the geographic franchise territories limit the ability to fully appropriate the benefits, and the timescales for achieving returns can be lengthy.

Rate regulation and the absence of marginal cost pricing dampen the market incentives for end-users to adopt the most energy-efficient technologies and management measures. These market imperfections deter private R&D investment and argue for a government role in supporting natural gas end-use R&D.

The GRI funding level was much greater than that of the DOE programs and complemented and enhanced them, sometimes providing substantial industry match into the smaller DOE programs. Also, the GRI did joint portfolio planning with DOE to ensure that the programs were complementary and non-duplicative. To a large extent, the sharp decrease in the DOE natural gas RD&D program funding in the 1980s is attributable to the existence of the larger GRI program and the prevailing view that oil and gas RD&D could be left to industry. However, there has been no restoration of the Federal natural gas RD&D program in response to the demise of the GRI program. Indeed, as seen in Table 8.1, the FY12 Administration budget request to Congress requests funding only for continuation of the natural gas hydrates program.

## The Impacts of DOE and GRI RD&D for Unconventional Natural Gas Supply

Box 8.1 in Chapter 8 provides a brief description of the DOE and GRI coal bed methane (CBM) and shale gas RD&D programs and their synergy with tax policy.

*Coal Bed Methane*[10]*:* The GRI Methane from Coal Deposits program focused on the development of the technologies needed to recover the CBM resource, with a focus on coal beds deemed un-minable at the time. The initial program objective was to develop technologies that would enable production of 0.1 to 1.0 Tcf per year of natural gas by 1990. Other objectives were aimed at locating appropriate coal deposits for economic recovery, developing drilling and stimulation techniques that increase methane flow rates without interfering with coal mining operations and developing satisfactory well completion techniques to manage water problems. Later objectives emphasized understanding the principles that govern coal bed cavity formation, fracture stimulation, and reservoir damage caused by operations. Ultimately, the GRI program was credited with developing cost-effective recovery of CBM from two different geologies: the shallow, thin but multiple beds present in Eastern Pennsylvania and the deep, thick bed coal present in Western Cretaceous. Technology transfer, largely to independent producers, was a major component of the program.

As seen in Figure 8.2, the GRI and DOE invested more than $120 million (1999 dollars) combined in their respective RD&D programs for CBM in 1978 to 1994.

*Shale Gas:* Shale gas has been commercially produced since the 1920s. By the late 1970s, approximately 70 Bcf of natural gas was produced annually from the shale gas resource. Production from these wells was characterized by low production rates that diminished very rapidly. The main limitations to shale gas production at the time were the inability of producers to confidently predict natural gas production rates from wells drilled both inside and outside historically drilled areas, and the inconsistent response of formations to stimulation techniques.[11] Two common beliefs at the time were that shale gas could be produced only if high natural gas prices persisted and that advancements in technology could do little to change this.

The DOE R&D program was complemented by a GRI gas shale R&D program. These programs can be credited for assessing the resource base and the expansion of knowledge on natural fracture networks. Core and fractigraphic analysis carried out by the DOE assisted in the deployment of massive hydraulic fracturing. The focus of the GRI program was on the commercialization and deployment of technologies that were of interest to the industry, including new logging techniques, reservoir models and stimulation technologies.

*Tax incentives:* Complementary policy mechanisms played a crucial role in accelerating unconventional natural gas production. Section 29 tax credits were put in place in 1980 and were provided to natural gas production from unconventional natural gas wells drilled between 1980 and 1992, with tax credits extending to natural gas produced from those wells until 2002. Unconventional wells received initial credits of around $0.54 per Mcf ($3 barrel of oil equivalent on an energy basis) and the value of the credits increased with inflation to above $1/Mcf in 2002. Approximately 9 Tcf of the CBM produced in 1980 through 2002 was eligible for the Section 29 tax incentives (not including natural gas that was produced from wells that were drilled before 1993 but came online after 1993). The use of Section 29 tax credits was limited by competition with other tax treatments, such as the Alternative Minimum Tax. The total value of the tax credit was equal to $760 million in 1993, shared mainly between producers of CBM and of tight gas.

According to a National Research Council (NRC) analysis,[13] DOE research, combined with research funding from GRI and the tax credit, resulted in an additional 1,740 bcf of natural gas between 1976 and 2005 directly attributable to the DOE's portion of the research funding; additional volumes were attributed to GRI research and the tax credit. The NRC report also noted that the Federal portion of the R&D funding resulted in "…realized economic benefits from royalties on Federal lands, increased state severance taxes and lower gas prices…estimated…to be $600 million." The programs had success by adapting production technologies to unconventional natural gas reservoirs in collaboration with the independent producers. The long-term reliable GRI funding commitment and the industry-led model for constituting the GRI Board and for RD&D portfolio development was crucial. The persistence of George Mitchell is generally credited with establishing the GRI focus in this area and with subsequent promising development of the Barnett shale in the 1990s.

### The Ultra-Deepwater and Unconventional Natural Gas and Other Petroleum Resources Research Program

The Energy Policy Act of 2005 established the Royalty Trust Fund to support a 10-year $500 million research program, focused primarily on natural gas supply and associated environmental issues. The program requires the establishment of a public/private partnership to manage natural gas and other petroleum supply research, paid for with revenues generated through Federal royalties paid by the oil and natural gas industry for energy production on Federal lands. As such, the program shares many of the features that characterized the GRI program: funding independent of annual Congressional appropriations; managed by a non-profit research management organization, with strong industry input to the research portfolio; industry cost-sharing; stable and predictable funding (at least in principle); Federal review of the annual program plan. A major difference is that the research program, less than a quarter the size of the GRI program at its peak, is restricted to supply, while the GRI program covered production all the way through end use. Another difference is that the regulatory approach used to generate the funding for GRI is replaced by a statutory approach, which is more appropriate to the deregulated market. This led to DOE rather than FERC being the responsible Federal entity for program oversight.

The Research Partnership to Secure Energy for America (RPSEA) was selected competitively to manage 75% of the Royalty Trust Fund, with the remaining 25% (as directed in statute) to be used by the National Energy Technology Laboratory (NETL) to establish a complementary in-house research program. RPSEA is structured as a consortium that includes service providers, universities, national laboratories, NGOs, state associations' service companies, and large and small producers. The funds awarded are allocated by law to three different program areas: ultra-deepwater resources (35%); unconventional natural gas resources (32.5%); and the technology challenges of small producers (7.5%). Cost sharing is required. It is noteworthy that over half of the unconventional resource portfolio is focused on shale gas and about 25% focuses on environmental issues in production,

**Table 8A.2 RPSEA Unconventional Onshore Program[14] (Dollar Amounts in Millions) (key: 2007, 2008, 2009)**

| Project Year | CBM | Gas Shales | Tight Sands | Project Funding |
|---|---|---|---|---|
| Integrated Basin Analysis | | New Albany (GTI) $3.40<br>Marcellus (GTI) $3.20<br>Mancos (UTGS) $1.10 | Piceance (CSM) $2.90 | **$10.60** |
| Drilling | | Drilling Fluids for Shales (UT Austin) $0.60 | | **$0.60** |
| Simulation and Completion | Microwave CBM (Penn) $0.08 | Cutters (Carter) $0.09<br>Frac (UT Austin) $0.69<br>Refrac (UT Austin) $0.95<br>Frac Cond (TEES) $1.60<br>Stimulation Domains (Higgs-Palmer) $0.39<br>Fault Reactivation (WVU) $0.85 | Gel Damage (TEES) $1.05<br>Frac Damage (Tulsa) $0.22<br>Foam Flow (Tulsa) $0.57<br>Fracture Complexity (TerraTek) $0.83 | **$7.32** |
| Water Management | | Integrated Treatment Framework (CSM) $1.56<br>Barnett & Appalachian (GTI) $2.50 | Frac Water Reuse (GE) $1.10 | **$5.16** |
| Environmental | * | Environmentally Friendly Drilling (HARC)* $2.20 | * | **$2.20** |
| Reservoir Description and Management | | Hi Res. Imag. (LBNL) $1.10<br>Gas Isotope (Caltech) 1.20<br>Marcellus Nat. Frac./Stress (BEG) $1.00<br>Fracture-Matrix Interaction (UT Arlington) $0.46<br>Marcellus Geomechanics (PSU) $3.10 | Tight Gas Exp. System (LBNL) $1.70<br>Strat. Controls on Perm. (CSM) $0.10<br>Fluid Flow I Tight Fms. (MUST) $1.20 | **$9.86** |
| Reservoir Engineering | | Decision Model (TEES) $0.31<br>Couple Analysis (LBNL) $2.90<br>Shale Stimulation (OU) $1.05 | Wamsutter (Tulsa) $0.44<br>Forecasting (Utah) $1.10<br>Condensate (Stanford) $0.52 | **$6.32** |
| Resource Assessment | | Alabama Shales (AL GS) $0.50<br>Manning Shales (UT GS) $0.43 | Rockies Gas Comp. (CSM) $0.67 | **$1.60** |
| Exploration Technologies | Coal & Bugs (CSM) $0.86 | Multi-Azimuth Seismic (BEG) $1.10 | | **$1.96** |
| **Total** | **$0.94** | **$32.28** | **$12.40** | **$45.62** |

Source: RPSEA's 2009, 2010 & 2011 annual plans.

including water management. Universities are the leads for nearly two-thirds of the projects in the unconventional portfolio.

Table 8A.2 highlights the portfolio of projects in RPSEA's unconventional onshore program.

Also of note is the distribution of RPSEA project leads by institutional type, shown in Table 8A.3. Universities dominate as awardees for the small producer and onshore programs, most likely a reflection of the lack of research capability of onshore operators, as noted earlier. This mix of participants also suggests a significant basic pre-competitive focus, as is appropriate for research at the frontiers of unconventional gas science and technology. Super-majors and large service companies dominate the offshore awards, where most of the expertise for producing in this extremely harsh and technically difficult province resides. The varied membership of RPSEA and the active engagement of over 1,000 scientists and engineers in the research planning and review processes provides a good model for public-private partnerships across the spectrum of research, development, demonstration, and deployment.

**Table 8A.3 RPSEA 2007 and 2008 Project Leads**

| | Small Producer | Onshore | Ultra-Deepwater | Total |
|---|---|---|---|---|
| For Profits | 2 | 2 | 16 | 20 |
| National Labs | 1 | 3 | 0 | 4 |
| Non-Profits | 0 | 3 | 5 | 8 |
| State Agencies | 0 | 2 | 0 | 2 |
| Universities | 10 | 18 | 7 | 35 |
| **Total** | 13 | 28 | 28 | 69 |

Source: RPSEA's 2009 and 2010 annual plans.

## NOTES

[1]Government Accountability Office, DOE Could Enhance the Project Selection Process for Government Oil and Natural Gas Research, December, 2008.

[2]U.S. Energy Information Administration, Financial Reporting System. Form 28.

[3]DOE Office of Budget. FY 1978 to FY 2012, DOE Budget Requests to Congress.

[4]Funding for natural gas in DOE's Office of Energy Efficiency and Renewable Energy is not targeted to gas. Building efficiency for example, is not fuel specific. As such, we have not analyzed funding in these areas.

[5]The Unconventional Natural Gas (UNG) subtotal does not include the first installment of Methane Hydrates program (1982–1992), the Secondary Gas Recovery Program (1987–1995), and the Deep Source Gas Project (1982–1992). These different programs were part of either the Environmental and Advanced Research Program or the Exploration and Production program and are therefore distributed in these totals.

[6]The program continued until 1999. However, after 1992, it became a subprogram under the Exploration and Development Program.

[7]Later known as the Environmental Research program and the Effective Environmental Protection program. It also excludes efficiency and electricity funding that could be apportioned to natural gas.

[8]Burnett, William M., Monetta, Dominic J., Silverman, Barry G. How the Gas Research Institute (GRI) Helped Transform the US Natural Gas Industry INTERFACES 1993 23: 44-58.

[9]"Building a Clean Energy Future," 2009 Annual Report, Gas Technology Institute.

[10]Gas Research Institute 1979–1983 to 1993–1997, Research and Development Plan. Chicago, Ill., Gas Research Institute.

[11]Gas Research Institute 1986–1990, Research and Development Plan. Chicago, Ill., Gas Research Institute.

[12]M.R. Haas and A.J. Goulding, ICF Resources Inc., "Impact of Section 29 Tax Credits on Unconventional Gas Development and Gas Markets." SPE 24889.

[13]Energy Research at DOE: Was It Worth It? Energy Efficiency and Fossil Energy Research 1978 to 2000. National Academy Press (2001), ISBN 0-309-07448-7.

[14]Not all awarded projects have been funded yet.

# Appendix 8B: Development and Utilization of Gas Turbines

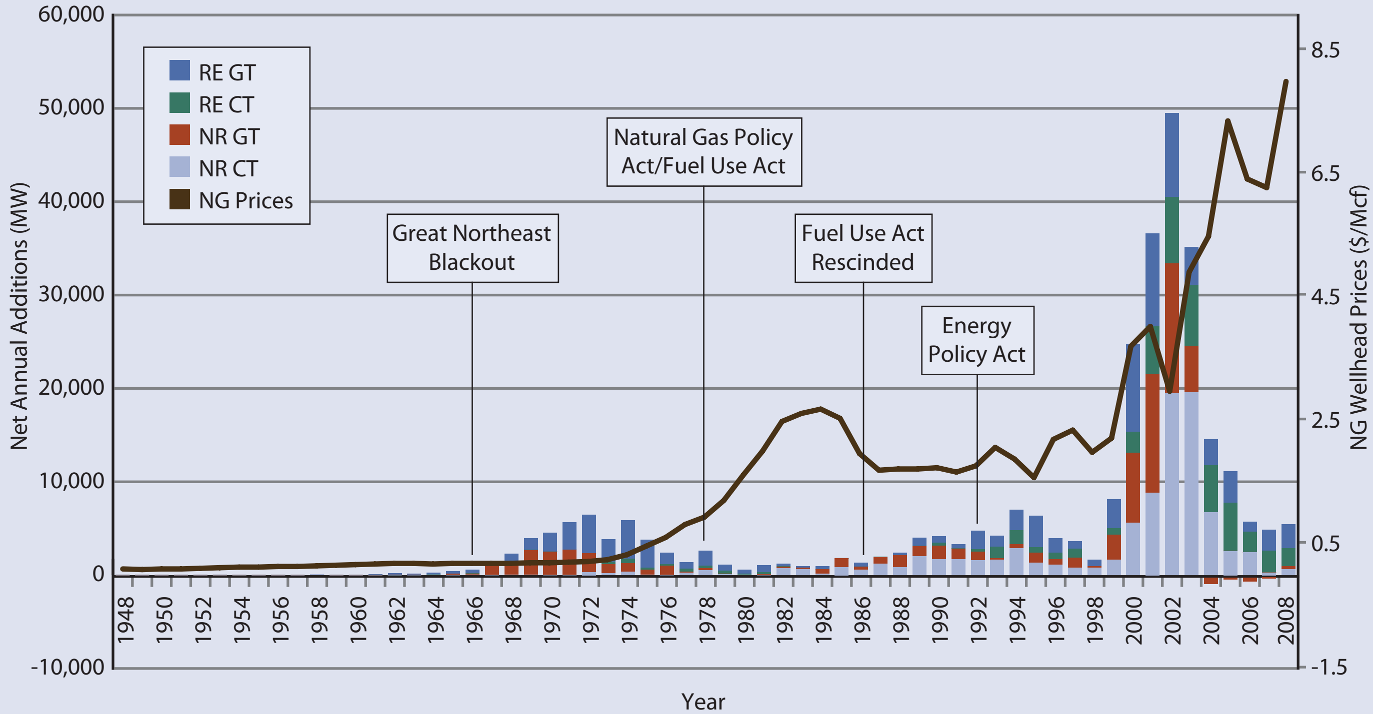
Development of unconventional natural gas supply and the application of gas turbines for electricity generation are arguably the two most significant natural gas-related energy technology developments of the last many decades. However, unlike unconventional natural gas, the Federal RD&D role in the development and deployment of gas turbines for electricity generation has had limited impact. Rather, the widespread adoption and utilization of gas turbines can be mainly attributed to the interplay of the following four factors: 1) the incremental technological advancements that were a result of military and industry RD&D efforts, 2) natural gas availability, 3) environmental concerns, and 4) the restructuring of the electricity sector.

Figure 8B.1 shows the introduction of gas turbines into the U.S. power generation sector. Clearly, government policy had a major impact on deployment of natural gas combined cycle (NGCC) technology. Repeal of the Fuel Use Act and restructuring of the electricity generation sector stimulated by the 1992 Energy Policy Act, together with relatively low natural gas prices in the 1980s and 1990s, eventually led to a major deployment — until natural gas prices began a major climb about a decade ago. In particular, the electricity deregulation policy environment combined with low gas prices, Clean Air Act restrictions on SOx and particulate emissions, high efficiency, low capital cost, and short construction times made NGCC units the overwhelmingly favored option for Independent Power Producers (IPPs). Annual deployment of gas turbines reached nearly 50,000 MW early in the last decade. Many of these investments were stranded when natural gas prices rose dramatically. A legacy of this is the underutilized NGCC fleet that was discussed in Chapter 4.

### Technology Development

As highlighted by Unger and Herzog[1], early technological advancements in gas turbines can be traced to government spending on defense programs that began during World War II and focused on developing and enhancing turbojets. The U.S. government spent upwards of $13 billion between 1940 and 1999 on jet engine development and continues to spend millions per year on RD&D efforts through companies such as GE and Pratt & Whitney.[2] The military RD&D program led to the development of highly efficient gas turbines mainly through advancements in heat-resistant blade materials and cooling technologies. The technological advancements achieved by the military program created a "supermarket of technology" that allowed the adoption of these technologies into industrial turbines.[3]

**Figure 8B.1 Annual Gas Turbine Net Additions and U.S. Natural Gas Prices. RE: regulated utility; NR: Not-regulated utility; GT: standalone combustion turbines (peaker unit); CT: the combustion turbine component of combined cycle units (topping cycle).**




Source: EIA Capacity Databases

United States government efforts directed specifically at gas turbines for power generation were limited to the small DOE High Temperature Turbine Technology (HTTT) program in the late 1970s, focused on coal-derived fuels, and the more recent Advanced Turbine Systems (ATS) program, launched in 1992. The ATS program was a DOE-industry cost-shared partnership aimed at higher efficiency. The program goal was to significantly increase turbine firing temperatures, enabling combined cycle efficiencies of 60% or more, and simultaneously lowering NOx emission levels. The goals were achieved in less than a decade through development of a suite of innovative materials, coatings, closed loop cooling and other technologies. Firing temperatures of 2,600° F and NOx emissions less than 10 parts per million were achieved without post-combustion cleanup. The results of the ATS program have been incorporated in the commercial offerings of the industry partners: the GE H-System Turbine and the Siemens Westinghouse Advanced W501G Turbine. The total cost of the program was approximately $470 million (1999 dollars) with the government accounting for approximately two-thirds.[4]

## NOTES

[1]D. Unger and H. Herzog, Comparative Study on Energy R&D Performance: Gas Turbine Case Study. MIT Energy Laboratory report EL 98-003 (1998).

[2]Ibid., p.19.

[3]Ibid., p. 19.

[4]Energy Research at DOE: Was It Worth It? Energy Efficiency and Fossil Energy Research 1978 to 2000. National Academy Press (2001), ISBN 0-309-07448-7.

# Appendix A: Acronyms and Units

## Acronyms

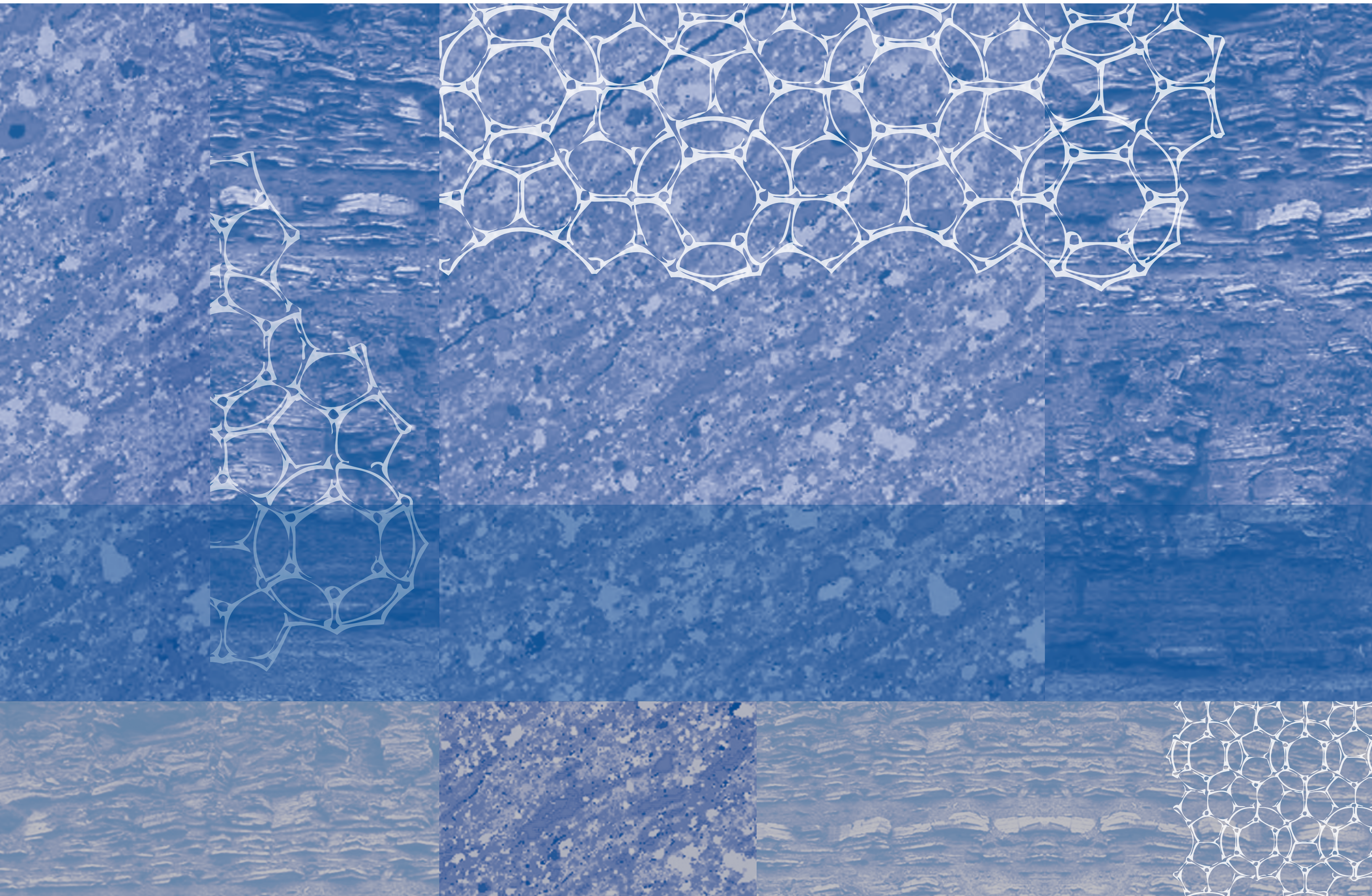
| | |
|---|---|
| AC | Air Conditioning |
| AEO | Annual Energy Outlook |
| AFUE | Annual Fuel Utilization Efficiency |
| AMT | Alternative Minimum Tax |
| ARI | Advanced Resources International |
| ARRA | American Recovery and Reinvestment Act |
| ATS | Advanced Turbine Systems |
| AU | Assessment Unit |
| BEP | Breakeven Prices |
| BOE | Barrels of Oil Equivalent |
| Bpd | Barrels per Day |
| BTC | Baku-Tbilisi-Ceyhan |
| $C_2$ | Carbon |
| CAA | Clean Air Act |
| CAIR | Clean Air Interstate Rule |
| $C_2H_6$ | Ethane |
| $C_3H_8$ | Propane |
| $C_4H_{10}$ | Butane |
| CBM | Coal Bed Methane |
| CCGT | Combined Cycle Gas Turbine |
| CCS | Carbon Capture and Storage |
| CGT | Combustion Gas Turbine |
| $CH_4$ | Methane |
| CHP | Combined Heat and Power |
| CNG | Compressed Natural Gas |
| $CO_2$ | Carbon Dioxide |
| $CO_2$-e | Carbon Dioxide Equivalent |
| COP | Coefficient of Performance |
| DCF | Discounted Cash Flow |
| DME | Dimethyl Ether |
| DOE | Department of Energy |
| DOT | Department of Transportation |
| DSDP | Deep Sea Drilling Project |
| DSM | Demand Side Management |
| DWPD | Drinking Water Protection Division |
| EER | Energy Efficiency Ratio |
| EERE | Energy Efficiency and Renewable Energy |
| EERS | Energy Efficient Resource Standard |
| EIA | Energy Information Agency |
| EIS | Environmental Impact Statement |
| EM | Electromagnetic |
| ENS | European Nuclear Society |
| EPA | Environmental Protection Agency |
| EPPA | Emissions Prediction and Policy Analysis (model) |
| ERCOT | Electric Reliability Council of Texas |
| ERDA | Energy Research and Development Administration |
| EUR | Europe |
| EV | Equivalent Variation |
| FDNP | Fully Dispatched NGCC Potential |
| FERC | Federal Energy Regulatory Commission |
| FFC | Full-Fuel Cycle |
| FRAC | Fracturing Responsibility and Awareness of Chemicals |
| FRCC | Florida Reliability Coordinating Council |
| FUA | Fuel Use Act |
| GAO | Government Accountability Office |
| GDP | Gross Domestic Product |
| GECF | Gas Exporting Country Forum |
| gge | Gallon of Gasoline Equivalent |
| GHG | Greenhouse Gas |
| GIIP | Gas Initially in Place |
| GOM | Gulf of Mexico |
| GRI | Gas Research Institute |
| GSGI | Global Shale Gas Initiative |
| GSHP | Ground Source Heat Pump |
| GT | Gas Turbine |
| GTI | Gas Technology Institute |
| GTL | Gas to Liquids |
| GWP | Global Warming Potential |
| H | Hydrogen |
| Hg | Mercury |
| HH | Henry Hub |
| HTTT | High Temperature Turbine Technology |
| HPR | Heat to Power Ratio |
| HRSG | Heat Recovery Steam Generator |
| HSPF | Heating Seasonal Performance Factor |

| | |
|---|---|
| ICF | ICF International |
| IEA | International Energy Agency |
| IECC | International Energy Conservation Code |
| IGCC | Integrated Gasification Combined Cycle |
| IMP | Integrity Management Program |
| INGAA | Interstate Natural Gas Association of America |
| IP | Initial Production |
| IPCC | Intergovernmental Panel on Climate Change |
| IPP | Independent Power Producer |
| IRR | Internal Rate of Return |
| ISMP | International Symposium of Mathematical Programming |
| ISO | Independent System Operator |
| ISO-NE | ISO-New England |
| L48 | Lower 48 |
| LCOE | Levelized Cost of Electricity |
| LNG | Liquefied Natural Gas |
| LPG | Liquid Petroleum Gas |
| MACT | Maximum Achievable Control Technology |
| MARAD | Maritime Administration |
| MARKAL | Market Allocation (model) |
| MCFC | Molten Carbonate Fuel Cell |
| Md | Mendelevium |
| MECS | Manufacturing Energy Consumption Survey |
| MISO | Midwest-ISO |
| MITEI | MIT Energy Initiative |
| MRH | Major Resource Holders |
| MRO | Midwest Reliability Organization |
| MTBE | Methyl Tertiary Butyl Ether |
| NAFTA | North American Free Trade Agreement |
| NEB | National Energy Board |
| NEPA | National Environmental Policy Act |
| NERC | North American Electric Reliability Organization |
| NESHAPS | National Emissions Standards for Hazardous Air Pollutants |
| NETL | National Energy Technology Laboratory |
| NG | Natural Gas |
| NGCC | Natural Gas Combined Cycle |
| NGL | Natural Gas Liquids |
| NGV | Natural Gas Vehicles |
| $NH_3$ | Ammonia |
| NIMBY | Not In My Backyard |
| NOGA | National Oil and Gas Association |
| NOx | Generic Term for the Mono-Nitrogen Oxides NO and $NO_2$ |
| NPC | National Petroleum Council |
| NPCC | Northeast Power Coordinating Council |
| NPV | Net Present Value |
| NRC | National Research Council |
| NREL | National Renewable Energy Laboratory |
| NYMEX | New York Mercantile Exchange |
| O+M | Operations and Maintenance |
| OCS | Outer Continental Shelf |
| ODP | Ocean Drilling Program |
| OECD | Organization for Economic Co-Operation and Development |
| OGIFF | Oil and Gas Integrated Field File |
| OGS | Oil-Gas-Steam (turbine) |
| OGWDW | Office of Ground Water and Drinking Water |
| OIT | Office of Industrial Technologies |
| OPEC | Organization of the Petroleum Exporting Countries |
| OPS | Office of Pipeline Safety |
| PAFC | Phosphoric Acid Fuel Cell |
| PCAST | President's Council of Advisors on Science and Technology |
| PEM | Proton Exchange Membrane |
| PFC | Perfluorinated Compounds |
| PGC | Potential Gas Committee |
| PHMSA | Pipeline and Hazardous Materials Safety Administration |
| PJM | Pennsylvania – New Jersey – Maryland |
| R&D | Research and Development |
| RD&D | Research, Development, and Deployment |
| RDD&D | Research, Development, Demonstration, and Deployment |
| ReEDS | Regional Energy Deployment System (model) |

| | |
|---|---|
| RES | Renewable Energy Standard |
| REX | Rocky Mountain Express Pipeline |
| ROW | Rest of the World |
| RPSEA | Research Partnership to Secure Energy for America |
| RTF | Royalty Trust Fund |
| RTO | Regional Transmission Organization |
| SAE | Society for Automotive Engineers |
| SCOP | Seasonal Co-Efficient of Performance |
| SEER | Seasonal Energy Efficiency Ratio |
| $SF_6$ | Sulfur Hexafluoride |
| $SO_2$ | Sulfur Dioxide |
| SOFC | Solid Oxide Fuel Cell |
| SPP | Southwest Power Pool |
| T+D | Transmission and Distribution |
| TMC | Transport Membrane Condenser |
| TTF | Title Transfer Facility |
| TVD | Total Vertical Depth |
| UIC | Underground Injection Control |
| UNG | Unconventional Natural Gas |
| USGS | United States Geological Survey |
| USREP | United States Regional Energy Policy |
| UTRR | Undiscovered Technically Recoverable Resources |
| WTI | West Texas Intermediate |

## Units

| | |
|---|---|
| bbls | Barrels of liquid |
| Bcf | Billion cubic feet |
| Bcfd | Billion cubic feet per day |
| Btu | British thermal units |
| cf | Cubic feet |
| GW | Gigawatt |
| GWh | Gigawatt hour |
| kW | Kilowatt |
| kWh | Kilowatt hour |
| Mcf | Thousand cubic feet |
| MJ | Megajoule |
| MMcf | Millions of cubic feet |
| MMBtu | Million British thermal units |
| MMTCe | Million metric tons of carbon equivalent |
| MW | Megawatt |
| MWe | Megawatt electric |
| MWh | Megawatt hour |
| psi | Pounds per square inch |
| qBtu | quadrillion $10^{15}$ British thermal units (Quad) |
| Tcf | Trillion cubic feet |
| $tCO_2$-e | Tonnes of $CO_2$ equivalent |
| TkWh | Trillion kilowatt hours |
| TWh | Terawatt hours |



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