An IHS CERA Special Report

Fueling North America's Energy Future

The Unconventional Natural Gas Revolution and the Carbon Agenda

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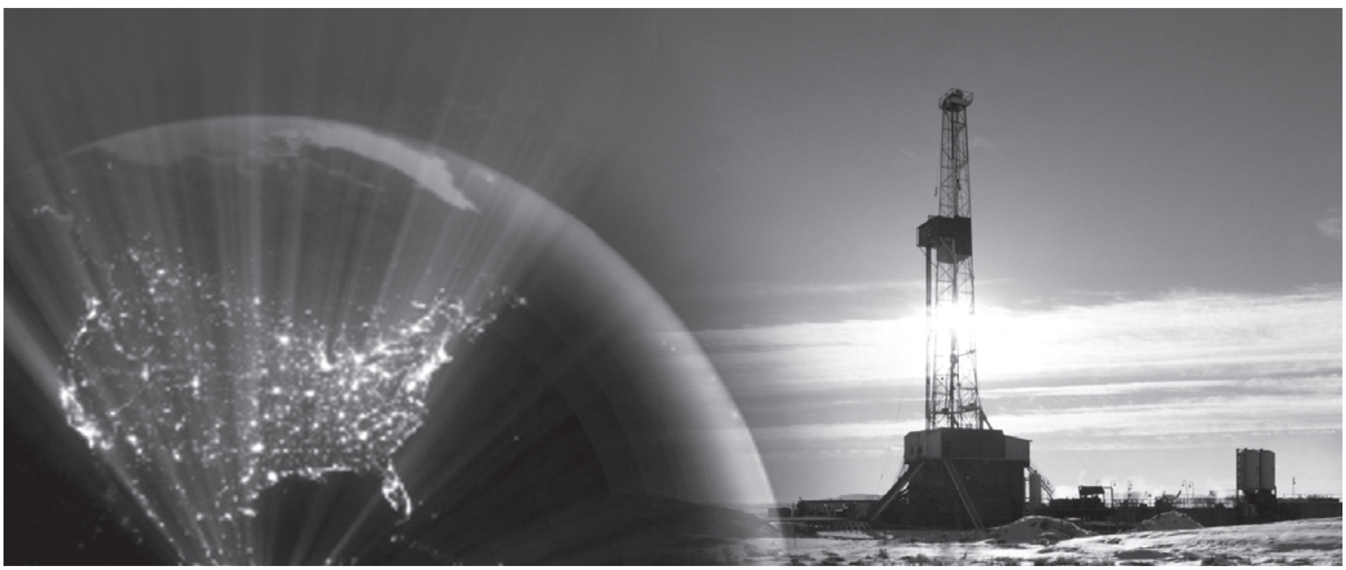

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Fueling North America's Energy Future:
The Unconventional Natural Gas Revolution and the Carbon Agenda

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IHS Cambridge Energy Research Associates (IHS CERA) hosted a series of workshops and meetings to gather expert input and a wide range of perspectives from the broader energy, environmental, and policy communities and discuss the outlooks and assumptions underpinning IHS CERA's analyses. These workshops were held across North America and involved 129 separate entities.

Workshops were held in Washington, DC; Calgary; San Francisco; and Chicago. Participation in these workshops does not in any way reflect endorsement of the content of this report, nor is this report in any way a summary of this input.

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FUELING NORTH AMERICA'S ENERGY FUTURE: EXECUTIVE SUMMARY

FUELING NORTH AMERICA'S ENERGY FUTURE: THE UNCONVENTIONAL NATURAL GAS REVOLUTION AND THE CARBON AGENDA

A major new factor—unconventional natural gas—is moving to the fore in the US energy scene and the national energy discussion. It is also of growing significance in Canada. It was only proved out over the course of the first decade of the twenty-first century. The scale was not even really recognized until 2007–08; and it did not enter the US national energy discussion until the second half of 2009. And yet it ranks as the most significant energy innovation so far this century—and one that, because of its scale, requires a reassessment of expectations for energy development. It has the potential, at least, to cause a paradigm shift in the fueling of North America's energy future.

This is the unconventional natural gas revolution—specifically, the emergence of shale gas. A veritable "shale gale" is transforming the supply and price outlooks for natural gas and the competition among energy options. Shale gas accounted for only 1 percent of US natural gas supply in 2000; today it is 20 percent. By 2035 it could be 50 percent. Shale gas and other forms of unconventional natural gas would underpin a significant increase in US natural gas consumption—and could allow the electric power industry to almost double its use of natural gas, from 19 billion cubic feet (Bcf) per day at present to 35 Bcf per day by 2035. An abundant natural gas resource shifts the choices for power generation technologies to meet both growing demand for electricity and the needs from retirements of aging power plants. It changes the relative costs for addressing greenhouse gas (GHG) emissions. It could also have an effect on transportation fuels—whether in the form of natural gas vehicles or via the turbine blades of a gas-fired power station that is, among other things, recharging the batteries of an electric vehicle.

The unconventional natural gas revolution has lowered the natural gas price outlook and made gas more competitive while encouraging higher expectations for security of supply—a dramatic shift from just half a decade ago. Furthermore most power producers have begun to expect that GHG limits in the future are less a matter of "if" than a question of "when and how much."

Yet, at the same time, there are also limits to the impact of shale gas that are imposed by the relative economics of fuels; the configuration of the power system and the requirements of reliability; the structure of the transportation system; and the uncertainties and potential imperatives of public policy, particularly in terms of GHGs.

This report seeks to address the impact of the "shale gale" on the energy system. It aims to provide a framework for understanding the potential impact of the unconventional gas revolution, a common basis for dialogue on the issues raised by it, and a context for fitting the changed outlook for natural gas into the discussion about power generation choices and reducing GHGs. The study does not seek to address the entire energy system and the full range of future options; that is beyond the scope.

CRITICAL ISSUES AND THE "SHALE GALE"

The issues around our central topic are critical. The emergence of the resource takes on particular significance at a time when the United States and Canada are grappling with the paths to a lower carbon future. Natural gas has about half the carbon content of coal, the mainstay of US power generation, which in turn accounts for about 40 percent of US GHG emissions. A new role for natural gas is emerging as the required "partner" for expanding renewable generation, which, while zero carbon, is also intermittent, depending on when the wind blows or the sun shines.

At the same time, in contrast to demand for transportation fuels, US power demand remains on a growth track. Even with increased efficiency, US power demand could grow over the next two decades by about a third, requiring 270 gigawatts of new capacity—equivalent to 540 new gas-fired or coal-fired units or more than 200 nuclear units. What will make up that capacity? That is a question that threads through this study.

IHS CERA has developed this report using a two-track process. We have drawn together stakeholders from all sides of the energy and environment spectrum—policymakers, electric utilities, natural gas producers and consumers, regulators, and nongovernmental organizations—to discuss the unconventional natural gas revolution, possible roles for natural gas and other fuels in the future energy mix, the drivers of the electric power industry and the interaction with emerging GHG policy, and transportation. Workshops were held in Washington, DC; Calgary; San Francisco; and Chicago to address the uncertainties and to identify areas of consensus and differences in viewpoint.

At the same time, IHS CERA carried out its own independent research and analysis. This study reflects that analysis, informed by the discussion and questions raised in the workshops. This study represents solely the views of IHS CERA. In this study, we may use US-specific illustrations of the United States' issues because of its greater overall scale, because the gas consumption is so much greater, and because it is more carbon intensive than the Canadian energy sector. However, the insights are as applicable to the issues Canada faces in achieving its own low-carbon future.

We hope that *Fueling North America's Energy Future* will make a substantive contribution to the national energy dialogue in both countries and provide a framework and basis for continuing discussion. We realize that the picture will continue to evolve. After all, only four years ago this topic would not even have been on the agenda. With so much changing, there is no singular moment for a definitive report. We welcome the dialogue and debate that this study will engender and encourage contribution by others to further elucidating and understanding these issues. But the study does start with the recognition of a new reality—how, through continual innovation and experimentation, a new energy option that was not obvious even half a decade ago has turned into a veritable "shale gale."

THE ROLE OF NATURAL GAS

Natural gas is one of the United States' major energy sources. It keeps about a quarter of the country running; that is, it provides almost 25 percent of total US primary energy demand. Natural gas demand was built up over the second half of the twentieth century, reaching more than 60 Bcf per day in 2009. Prior to that it was a local fuel. During World War II, as pressure mounted on US oil supplies, President Franklin Roosevelt wrote to his Secretary of the Interior, "I wish you would get some of your people to look into the possibility of using natural gas. I am told that there are a number of fields in the West and the Southwest where practically no oil has been discovered but where an enormous amount of natural gas is lying idle in the ground because it is too far to pipe to large communities."*

It was only after World War II that these fields were connected to markets. With that came a great expansion. For in the decades that followed, natural gas turned into a continental energy resource, facilitated by the development of an expanding network of major pipelines that tied producing areas to demand centers. It became a major fuel source for homes, industry, and power plants.

But from the beginning of the twenty-first century until 2007, it was generally thought that natural gas was in tight supply and that, as a result, the United States would become a growing importer of liquefied natural gas (LNG) in order to meet the increasing gap between rising demand and constrained US and Canadian supply.

SIX KEY QUESTIONS

The unconventional revolution shifts natural gas from a constrained energy resource to an abundant one. In so doing it raises many questions. This study addresses six sets of questions that are key to the energy future:

- How large is the gas resource base opened up by the shale gas revolution, and what are the financial costs and the footprint of its development?
- What factors could limit the realization of the potential of unconventional natural gas? What are the environmental issues associated with its development?
- Does this greater abundance of natural gas mean that gas prices are now on a lower and more stable trend, or is this the bottom of a cycle?
- What are the growth markets for natural gas, and in particular, what are the prospects in transportation?
- What are the growth prospects in electric power? Under what constraints—technical, economic, and political—do electric power providers operate, and how might the changed fuel supply picture affect investment decisions that utilities make and regulators approve?
- How significant a role can natural gas play in achieving reductions in GHG emissions along with such other options as nuclear energy, renewable energy, and carbon capture and storage (CCS)?

*Daniel Yergin, *The Prize: The Epic Quest for Oil, Money, and Power* (New York: Free Press, 2009, new edition), p. 361.

Changes can occur relatively quickly in the overall energy system, but large changes require time. The vast sums invested in the energy supply chain and the long investment lead times prevent major overnight changes in the fuel and technology mix—today's investment decisions will, to a great extent, determine the outcome 20 or 30 years from now. Greater certainty in government policy would certainly facilitate the investment process. This particularly applies to the policy decisions that will determine how, at what cost, and to what degree North America will decarbonize its energy system. Uncertainty about the policy framework creates delay and postpones investment decisions.

KEY FINDINGS

The New Natural Gas Resource Is a Game Changer

- North American discovered natural gas resources have increased by more than 1,800 trillion cubic feet (Tcf) over the past three years, bringing the total natural gas resource base to more than 3,000 Tcf, a level that could supply current consumption for well over 100 years.
- Development of this expanded resource may be able to meet significantly increased levels of demand without significant increases in prices.
- Shale gas alone is expected to grow to more than 50 percent of the supply portfolio by 2030.
- Indigenous natural gas supplies reduce the need for LNG imports into North America—which become a matter of choice rather than necessity.

The combination of hydraulic fracturing (fraccing) and horizontal drilling has opened up vast new resources of natural gas from shale formations and tight sandstones. These innovations have unlocked the potential of natural gas shales that have greatly increased the potential supply of natural gas in North America and at a much lower cost than conventional natural gas. IHS CERA's analysis of the emerging natural gas plays in North America points to an aggregate discovered resource base of some 2,000 Tcf and a total, including what is expected to be found in the future, of more than 3,000 Tcf. In the United States alone the new natural gas plays have increased the resource base by more than 1,100 Tcf. This is an order of magnitude larger than the proved reserves recognized by the US Energy Information Administration (EIA) only two years ago. In addition, the estimated shale gas resources in Canada exceed 500 Tcf. If there were sufficient market demand, the scale of the resource would allow North American natural gas supply to grow dramatically.

At the same time, the outlook for the cost of supply has fallen from more than $6 per million British thermal units (MMBtu) to less than $5 per MMBtu because shale gas development is lower cost than most conventional sources of natural gas supply. Unconventional gas changes the supply risks from those of the traditional exploration and production business to those more akin to the manufacturing business. Great focus will be directed to improving efficiencies throughout the supply chain and to continuing to drive down costs.

Shale Gas Brings Benefits and Environmental Impacts

- Natural gas has a lower carbon footprint—about half that of coal—and results in negligible emissions of sulfur dioxide (SO_2), nitrogen oxides (NO_X), mercury, and particulates in contrast to other fossil fuels.
- The local impacts—land disruption, air quality, and noise disturbance—occur during the drilling and completion phase (two or three months) rather than the production phase (20 to 40 years).
- Water has emerged as the highest visibility environmental issue with shale gas. A comprehensive regulatory framework for well construction and water management is already in place with the objective of protecting drinking water supplies. Deeper dialogue between industry and other stakeholders is required, as well as greater transparency and understanding of the technology, geology, and the current highly regulated system of water management.

The greatest attraction of natural gas, from an environmental perspective, is that it results in the lowest carbon dioxide (CO_2) emissions of any fossil fuel, meaning that it has significant potential to help address global climate change concerns. All types of energy involve trade-offs among local environmental impacts, economic development, and wider impacts on the environment or climate. Shale gas resources are no exception, and raise both positive and negative issues for the environment and for local communities and local economies.

Environmental concerns focus on two water issues: Will the water and chemicals used in fraccing seep into drinking water? And is the "produced water" that comes out of the wells sufficiently well-managed to avoid contamination? There is considerable geological separation, including impermeable rocks, between the underground fraccing sites and drinking water aquifers. "Produced water" requires management in all oil and gas drilling. The well-drilling process, including water management, is regulated at the state and local levels. Prior to drilling, operators must obtain a permit that generally includes approval of the well location, well design, and plan for restoring the location after drilling is complete. Environmental impact statements review the potential environmental impacts and establish plans to mitigate them. The states regulate the fraccing process and the US Environmental Protection Agency (EPA) regulates produced water management under the Safe Drinking Water Act and the Clean Water Act. The EPA has delegated its regulatory authority to most of the states with oil and gas production.

Oil and gas operations are widespread throughout North America, and drinking water supplies appear to have been safeguarded from contamination. This suggests that the risks can be managed and that shale gas development can proceed safely, with proper industry management and regulatory safeguards in place. These issues will be better understood and handled through collaboration, research, and transparency, and with an understanding of the current regulatory system.

New Shock Absorbers for Natural Gas Supplies

- Price spikes for natural gas are of particular concern to electric power generators and other large end users.
- Volatility and price variations are essential mechanisms that send signals to consumers and suppliers to balance the market. The extremes, however, can be destabilizing with very adverse results—and thus the need for "shock absorbers" to reduce the impact of hurricanes or other events that might temporarily disrupt supplies.
- The newfound expansion of unconventional gas, combined with the expansion of LNG import facilities in the United States and Canada and increased storage, has introduced new supply shock absorbers to respond to disruptions and market imbalances.
- Past experience of natural gas prices raises a question among large users as to whether relatively more stable prices are at hand, as opposed to the bottom of a cycle. As the giant new shale gas plays are brought into production, end-user confidence in the long-term sustainability of shale gas supply will likely grow.

Based on experience, a prevalent anxiety about natural gas concerns the lack of adequate "shock absorbers" that allow the supply system to respond to sudden unexpected increases in demand or loss of supply. Such a lack makes the market vulnerable to demand increases, creating high and sometimes protracted price increases that undermine investment by power generators and other end users. But the advent of shale gas brings on a major new shock absorber—an abundant new supply source that can respond relatively quickly to changes in demand compared to more traditional sources of gas supply. Combined with expansion of LNG regasification and storage capacity, shale gas means that the natural gas market will now have a more complete set of shock absorbers that should shorten the time needed to rebalance the market.

These shock absorbers will not eliminate price volatility. Indeed, price volatility will continue to signal the existence of market imbalances that require a supply or demand response. However, the new market dynamics made possible by these shock absorbers will allow quicker supply responses to price signals indicating shortage and may help to prevent an unexpected sustained step up in natural gas prices.

New Supply Potential and Demand Options

- Residential, commercial, and industrial natural gas demand have registered long-term declines that may be moderated but are unlikely to be reversed.
- The major source for rapid growth in natural gas demand is the electric power sector. Power demand growth is extremely likely as new uses for electricity (possibly including electric vehicles) overcome the effects of energy efficiency and conservation.
- Much of any electricity demand growth will be met by gas-fired generation. Natural gas demand from the US power sector could grow from roughly 19 Bcf per day today to as much as 35 Bcf per day by 2030.
- Natural gas–fired power plants have cost, timing, and emissions advantages compared to coal-fired plants. However, natural gas use for power generation over the long term depends on how strict GHG emissions targets will be and how other competing or complementary technologies (nuclear, CCS, and renewables) develop over time.
- The infrastructure needs and higher costs will likely limit significant growth in natural gas vehicles, which now number a few hundred thousand in the United States. Very significant policy support would be needed, which would compete with policy support for higher efficiency, biofuels, and electric vehicles. The most likely growth market for natural gas in transportation would be through the electric power sector.
- LNG exports from either British Columbia or Alaska (already an LNG exporter) may be competitive into high priced oil-linked Asian markets, but significant exports from the US Lower 48 are problematic.

The "shale gale" creates opportunities for a range of new uses for natural gas. Residential, commercial, and industrial demand all appear to be in long-term decline (with the possible exception of demand in the Canadian oil sands). There is renewed interest in using natural gas in vehicles, both providing a market for natural gas and reducing oil usage. However, the very large infrastructure costs associated with natural gas usage on a large scale in transportation, combined with the time lags to change the auto fleet, constitute a major obstacle. Moreover, natural gas vehicles have to compete with increased auto efficiency, which affects the economics as well as policy commitments to biofuels and electric vehicles. The most obvious area of growth would be urban fleets, which can be fueled from a central source. Natural gas may gain its largest role in transportation fueling electric power plants that, among other things, help recharge electric vehicles.

The power sector holds the greatest potential for growth in natural gas consumption in both the short and long term. The power sector is reevaluating its future generation mix, in light of environmental and cost considerations, as well as shifting fuel options. The new outlook for natural gas expands the opportunities for natural gas in the climate change debate.

There Is No Single Fuel or Technology of Choice in the Power Sector

- The abundance of new natural gas will increase the share of natural gas–fired generation in the North American power sector.
- It will expand the role of natural gas–fired generation technologies to back up renewable power resources—a new role for natural gas
- Natural gas–fired generation consumed 3 Bcf per day more natural gas in 2009 than in 2008 when adjusted for the impact of the Great Recession. Displacement of coal-fired generation contributed significantly to this number. But there is a limited pool of "spare" gas-fired capacity that prevents wholesale displacement of coal with natural gas.
- In addition to this fuel switching, the power sector can reduce near-term CO_2 emissions by replacing existing coal-fired plants with new gas-fired plants and converting existing coal-fired plants to burning gas. This would require substantial investment and would result in growth of natural gas use. But power companies would be concerned about longer-term requirements to further reduce CO_2, which would also affect gas-fired facilities.
- The power industry has a multiple-decade planning horizon. If the goals include cutting carbon emissions substantially over the long term, such as the often-cited 80 percent reduction by midcentury, aggressive development and deployment of zero-carbon technologies, including nuclear and CCS, will need to take place today.
- But a gas-based solution, on its own, does not provide a long-term path to a low-carbon future. To get there will require a portfolio of options including not only natural gas but also some mix of nuclear power, renewables, and breakthroughs in CCS.

Economic and technical factors create roles for a spectrum of power generation technologies—to provide base load, cycling, and peaking capacity and to maintain grid stability. No single technology or fuel provides the lowest cost of electric production to meet all requirements of the power supply process. However, the desired portfolio of generating options changes over time as technological innovation alters expected cost and performance of different generating technologies and as expectations for capital, fuel supply, and (prospectively) GHG emissions costs change.

The power industry will likely increase the share of natural gas in the fuel mix because of the carbon footprint of natural gas–fired generation and because it can be built more quickly and easily than coal, nuclear, or hydro and will benefit from credible expectations of lower long-term natural gas prices. This will help meet carbon targets in the next two decades. However, an 80 percent national target for carbon reduction by 2050 would imply that the entire CO_2 output from a much larger power system would equal today's CO_2 output just from natural gas generation—which represents only 20 percent of power sector emissions. Thus, power companies face a quandary in making their longer-term fuel choices. Every choice brings challenges. Given demand outlooks, just to keep nuclear power at its current 20 percent share of total US generation would require building 40 gigawatts of new nuclear plants over the coming two decades. The pace of nuclear additions needs to pick up beyond the next two decades to maintain nuclear's 20 percent share because of anticipated retirements.

One version of the quandary therefore comes down to this: Should power companies build combined-cycle gas turbine plants, which are much easier to permit and quicker to build, and take the risk that they may be unable to operate for their planned technical life span because of the encroachment of GHG emissions limits? Or should they build nuclear power plants, which are more expensive and take longer to build and are more difficult to permit, that are not subject to this risk but may turn out not to have been necessary if GHG emissions limits are less stringent than currently proposed?

Carbon Capture and Storage—The Scale and Uncertainties

- If the often-mentioned 80 percent reduction target for CO_2 emissions are to be met, either fossil fuel usage—including natural gas—will have to be dramatically reduced or CCS will be required.
- The state of technology for CCS needs to advance significantly if it is to be cost competitive with clean energy alternatives such as nuclear or hydropower.
- Commercial, utility-scale CCS has not been demonstrated. The scale of North American CO_2 daily emissions from the power sector alone (in dense phase, "liquid" conditions) exceeds three quarters of global daily oil supply volumes.
- Policy to deal with legal liability and pore space ownership issues will be required just as much as support for expansion of research and development (R&D) efforts to demonstrate utility-scale CO_2 injection.

If fossil fuels—natural gas or coal in the power sector—are to be viable in a future era in which GHG emissions are significantly limited, technologies must be developed to remove their intrinsic carbon. Demonstration plants to strip the CO_2 from the flue gases of coal-fired power stations have confirmed the technical feasibility of carbon capture. Similarly, geological CO_2 storage (by injecting it into subsurface formations) has been demonstrated. However, the size of demonstrations has been at least an order of magnitude smaller than utility scale.

Moreover, given the requirements of CCS at utility scale, a new system of regulation and ownership would have to be developed, including perhaps a concept of "eminent subdomain," which would certainly be controversial.

Innovation is required to dramatically reduce the costs of CCS at scale. But the size of the challenge and levels of R&D investment to make the required breakthroughs may be significantly underestimated. Innovation can often deliver surprises. The "shale gale" is an obvious case in point. If the objective is to meet the 80 percent target for reducing GHG emissions, what will be required is a range of options that includes some form of CCS, nuclear, renewables including hydropower (the most readily available source of reliable, dispatchable, renewable power), and natural gas—and, no doubt, technologies that are not yet mature or even evident.

CHAPTER I: THE “SHALE GALE”— A GAME CHANGER FOR THE NATURAL GAS INDUSTRY

A SHORT GUIDE TO UNCONVENTIONAL NATURAL GAS

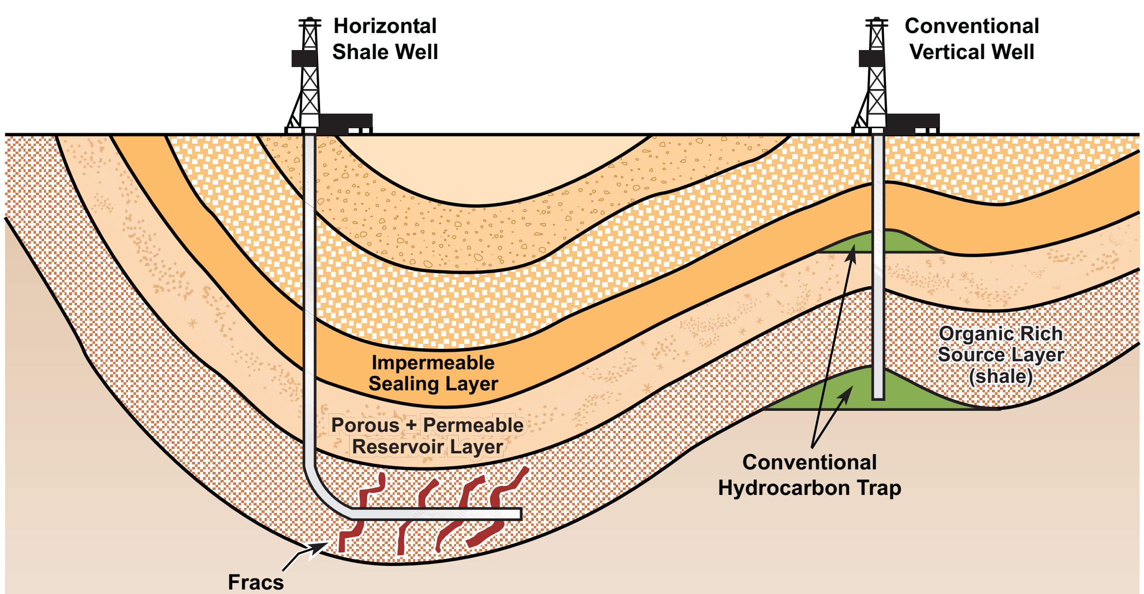
What Is Unconventional Natural Gas?

To understand unconventional natural gas, one has to understand where it comes from. Unconventional natural gas is distinguished from conventional natural gas because of the types of reservoirs in which it is found. In a conventional reservoir natural gas has migrated from a source rock into a "trap" that is capped by an impermeable layer of rock (sometimes in association with deposits of crude oil). A well is drilled into the reservoir to allow the natural gas to flow into the wellbore and then to the surface.

Unconventional natural gas production techniques allow recovery of natural gas that remains trapped in the source rock, unable to migrate into a reservoir because of the low permeability of the source rock. The most prominent types of unconventional natural gas are coalbed methane (CBM), gas from tight sands ("tight gas"), and shale gas.

- CBM is natural gas that is trapped in underground coal deposits. CBM has been produced commercially since the 1980s and today accounts for approximately 8 percent of total natural gas supply in North America.
- Tight gas commonly refers to natural gas trapped in sandstones from which it is unable to migrate. Extraction from such reservoirs requires either or both of the production techniques described here. Tight gas accounts for about 25 percent of current North American natural gas production.
- Shale gas is trapped in shale formations. (Ironically, these shale formations can also be a source rock or a cap rock for a conventional reservoir.) Extraction requires either or both of the production techniques described here. Shale gas currently accounts for 17 percent of total North American natural gas supply and is expected to be the fastest growing source of supply in coming decades. In 2006 it was only 1 percent of supply.

NATURAL GAS
Traps versus Shales



Source: IHS CERA and Devon Energy.
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Production Technologies

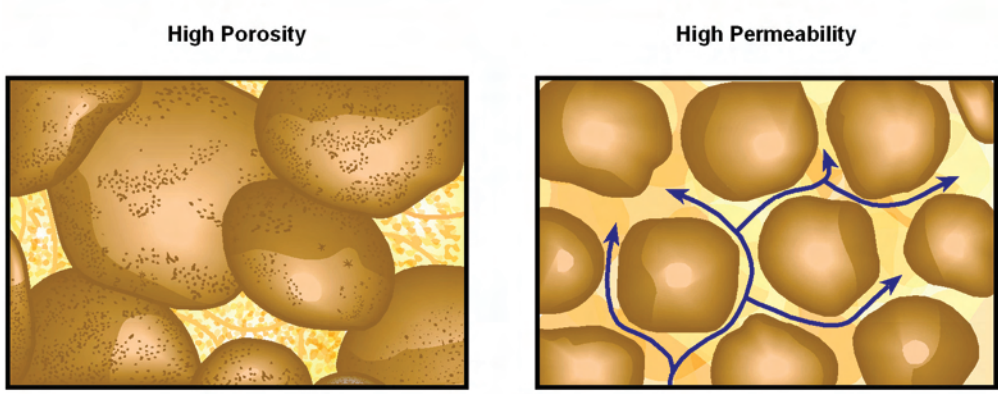
Two technologies—hydraulic fracturing and horizontal drilling—are critical to producing unconventional natural gas. Each technology has been in use for decades, but the combination of the two procedures was the key to igniting the unconventional natural gas revolution.

- Hydraulic fracturing (commonly called *hydrofraccing* or simply *fraccing*) involves the injection of fluid (usually a mixture of water, sand, and chemicals) under high pressure into a natural gas or oil well to create new fractures in the reservoir rock or to enlarge existing ones. The fraccing fluid contains solids (commonly sand) called *proppants*, which hold the fractures open after the procedure is completed. This process creates pathways for natural gas or oil contained in the rock to move into the wellbore and then to the surface. Fraccing has been used commercially in the United States since 1949 for stimulating production from both oil and gas wells and to date has been used in 1 million wells. It has proved essential to releasing natural gas from shale rock because of the density of the shale.
- Horizontal drilling has also been instrumental in increasing production volumes from natural gas and oil wells. This technique involves drilling a vertical well to the desired depth and then drilling laterally to access a larger portion of the reservoir. Used extensively in the 1980s in the Austin Chalk oil formation in Texas, horizontal drilling spread through the industry in the 1990s.

Other techniques for stimulating production from low permeability reservoirs include an "alphabet soup" of different options, including gravel packs, propped fracs, frac-'n'-pacs, and "barefoot completions." All of these are variants on the theme of accelerating production by exposing a larger surface area of the reservoir rock to a well. This allows fewer wells to be drilled in a field, or increases reserves from mature fields by producing previously uneconomic resources. Horizontal drilling and hydraulic fracturing now allow commercial production from formations so tight that gas had been unable to escape from them over millions of years of geological time.

Porosity and Permeability

Two of the most important properties that determine a rock formation's suitability as a reservoir are its porosity and permeability. These are related concepts. Porosity refers to the amount of empty space (pores) between the granular material that makes up the rock. Permeability measures how easily fluids can flow between the pores. A porous rock may not be very permeable if the void spaces are not highly interconnected. Sandstone is typically a porous rock with high permeability. Tight sands are porous sandstones with low permeability. Shale is an example of a porous rock with low permeability. Thus the first is a source of conventional natural gas, whereas the latter two yield unconventional gas, requiring some kind of stimulation to flow at commercially viable rates.



Source: IHS CERA.
00112-31

CHAPTER I: THE "SHALE GALE"—A GAME CHANGER FOR THE NATURAL GAS INDUSTRY

- North American discovered natural gas resources have increased by more than 1,800 trillion cubic feet (Tcf) over the past three years, bringing the total natural gas resource base to more than 3,000 Tcf, a level that could supply current consumption for well over 100 years.
- Development of this expanded resource may be able to meet significantly increased levels of demand without significant increases in prices.
- Shale gas alone is expected to grow to more than 50 percent of the supply portfolio by 2030.
- Indigenous natural gas supplies reduce the need for liquefied natural gas (LNG) imports into North America—which become a matter of choice rather than necessity.

The North American energy discussion has significantly changed course in less than a year. The decisive change is the shift from concerns about scarcity and high cost of natural gas to the implications of an abundant indigenous natural gas resource base and growing production from resources that heretofore were considered technically and economically inaccessible. The potential of shale gas was not even evident at the beginning of this century; its presence in the supply mix was almost imperceptible until 2007–08. Yet today it ranks as the most significant energy innovation so far of this century.

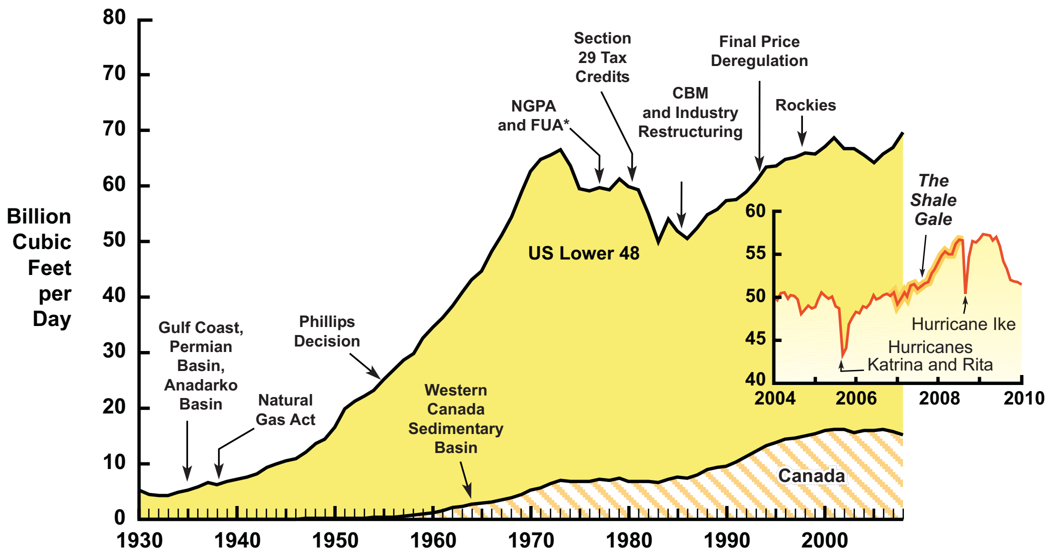
The extent of the shale resource is far from clear. Its full potential is not yet clearly understood because it is still early in the life of the development of the resource, a consideration of particular importance to end users facing long-term investment decisions. But based on current research, the shale gas resource base in the United States is now understood to be many times larger than estimates of conventional proved reserves reported by producers to the Energy Information Administration (EIA) of the US Department of Energy (DOE). Additional shale gas resources exist in Canada, some of which are already under development. In addition, shale gas resources may extend into Mexico.

The first substantial indication of the scale of this potential came in 2007 and 2008, when US lower-48 natural gas production grew from a low of 49 billion cubic feet (Bcf) per day in January 2007 to almost 57 Bcf per day in July 2008—an increase of 15 percent in just 18 months (see Figure I-1). The achievement was all the more remarkable because it occurred in the world's largest natural gas market and because it was not attributable to the impact of any single large project but rather to multiple contributions from a range of different operators in a dispersed resource base.

During these same two years EIA's estimates of proved natural gas reserves grew by 16 percent—from 211 trillion cubic feet (Tcf) at the end of 2006 to 245 Tcf at the end of 2008. The EIA started reporting shale gas reserves separately in 2007 (22 Tcf in 2007, growing

Figure I-1

North American Dry Natural Gas Production, 1930–2008



Source: IHS CERA.
*Natural Gas Policy Act of 1978 and Fuel Use Act.
00112-4

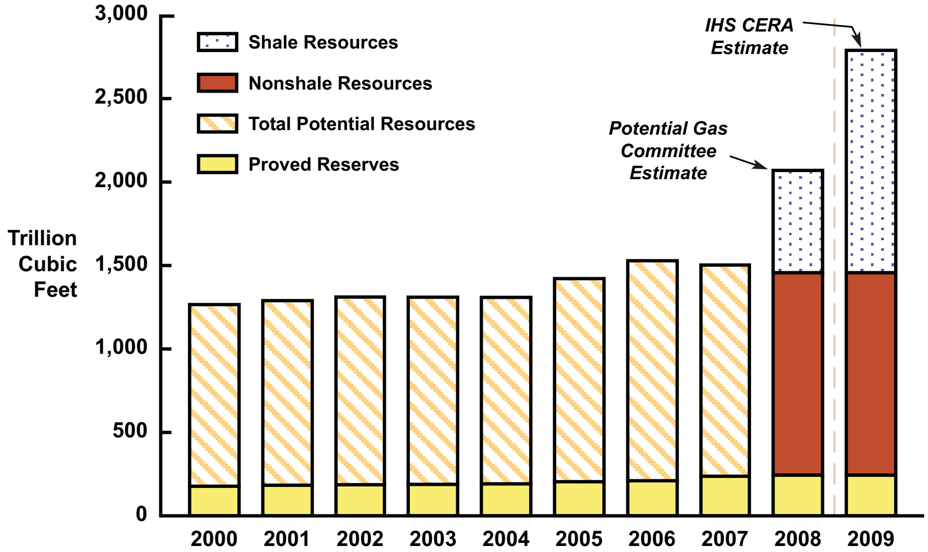
to 33 Tcf in 2008).* *Proved reserves* is the narrowest of the commonly used measures of potential supply. The Potential Gas Committee (PGC) of the Colorado School of Mines uses an alternative, broader approach to estimate resources. In addition to EIA's proved reserves estimates, the PGC adds its estimates of probable, possible, and speculative resources. The PGC estimates that the total potential of US gas supply increased by 35 percent between 2006 and 2008, and now amounts to 2,076 Tcf—a 90-year supply at current rates of consumption. Of this total, the PGC broke out the shale gas component separately for the first time in 2008 at 615 Tcf—a figure that IHS CERA estimates to have risen by an additional 515 Tcf. This would bring the total US resource estimate to more than 2,500 Tcf (see Figure I-2). In addition, the estimated shale gas resources in Canada exceed 500 Tcf, adding further to the aggregate North American natural gas resource inventory.

Already the shale gas resource has made a significant contribution to natural gas supply in the US Lower 48, growing from about 5 percent of total production in 2006 to an estimated 20 percent by 2009. (All unconventional gas, including tight sands, CBM, and shale gas, now represent one half of total natural gas production.) Drilling activity in British Columbia has not yet led to supply increases, as these development areas await pipeline infrastructure to bring gas to market.

*US EIA based on US Securities and Exchange Commission proved reserves disclosures.

Figure I-2

US Natural Gas Reserves and Resources



Sources: EIA, PGC,and IHS CERA.
00112-27

A CYCLICAL OR A SECULAR CHANGE?

However, recent experience would suggest caution about such estimates, especially for electric utilities and industrial consumers. For this is not the first time that natural gas has appeared to be abundant. In the second half of the 1990s natural gas—considered at the time to be inexpensive and widely available—became the favorite fuel for new electric power development. But at the beginning of this century, in the face of higher demand and stagnant supplies, natural gas prices began to rise sharply, creating severe problems—and in some cases bankruptcies—for many companies that had counted on long-term supplies of inexpensive natural gas. For the next several years North American natural gas supplies were constrained, and concerns mounted about the adequacy of supplies. It was expected that the continent would become increasingly dependent upon imports of LNG to fill the gap. Today, however, the emergence of shale gas is beginning to radically change both that perception and the dynamics of both the North American and global gas markets. But memories of the past decade are still fresh for many utilities and industrial end users.

NATURAL GAS DEVELOPMENT IN THE UNITED STATES—COMING FULL CIRCLE

Natural gas has a long history in the United States. The first natural gas well was drilled in 1821 by William A. Hart in Fredonia, New York, almost 40 years before Colonel Edwin Drake drilled his oil well in Titusville, Pennsylvania. Ironically this first well was an "unconventional" shale gas well—drilled into the Fredonia Shale formation, a Devonian shale in the Appalachian Basin.*

Viewed in this context, the natural gas industry has marked a 190-year cycle, coming full circle to the Appalachian Basin's Marcellus Shale play—another Devonian-aged shale. However, it was more than a century after the initial discovery that the pipeline infrastructure was built to move natural gas to major markets. Natural gas development came to be focused in states such as Texas, Oklahoma, and Louisiana and eventually spread offshore into the Gulf of Mexico. It was after World War II, particularly in the 1950s and 1960s, that the complex pipeline network was put in place to allow natural gas to play a significant role in the North American energy mix, establishing natural gas as a continental fuel.

Decades of Regulation

The US natural gas industry was heavily regulated for decades. The Natural Gas Act of 1938 gave the Federal Power Commission (FPC) authority over interstate pipeline construction, interstate natural gas transportation services, natural gas imports and exports, and rates charged for the interstate transportation and sale of natural gas. In 1954 the US Supreme Court in its "Phillips Decision" ruled that the FPC had jurisdiction over the rates of all natural gas sold into interstate commerce, extending federal price regulation to the wellhead.**

Two decades of wellhead price controls ensued, misaligning costs and prices and, as a result, removing incentives to explore for and develop natural gas. Many companies focused on the search for oil and were disappointed when a well turned up only natural gas. Despite these drawbacks, the natural gas resource base was strong enough to support a steady increase in demand until 1972, when production peaked to support demand of more than 60 Bcf per day. At that time the wellhead price of natural gas was 19 cents per million British thermal units (MMBtu), only 3 cents higher than it had been ten years before. There followed a long decline in natural gas consumption as production was unable to keep up with demand at the regulated low prices. Shortages developed in the interstate natural gas market—but not in intrastate natural gas markets, which were not subject to federal price controls. These interstate shortages created crises and rising political concern.

By 1978 the regulated prices had moved so far out of balance with the supply-demand fundamentals that some kind of action became unavoidable. The result was the Natural Gas Policy Act of 1978, which aimed at moderating and eventually phasing out price controls over a period of time. The legislation, highly contentious in its development, extended price regulation to intrastate markets and established a complex system of price ceilings for many different categories of natural gas. This could be only a temporary solution, and most of

*Devonian shales are so named because they developed from the compacting of muds deposited during the Devonian period of the Paleozoic era, about 360 million years ago.
**In 1978 the FPC was replaced by the Federal Energy Regulatory Commission (FERC).

these categories were put on a schedule for eventual decontrol. To eliminate what was called "excess demand," the Powerplant and Industrial Fuel Use Act restricted the use of natural gas or oil in new power plants or industrial boilers and encouraged coal or nuclear energy instead.* The logic was that natural gas was a "premium fuel"—best for priority uses such as home heating. Coal and nuclear could take its place in power generation based on the belief that natural gas resources were insufficient to support any growth in demand from the industrial and electric power markets.

The decade of the 1980s was chaotic for the natural gas industry. Economic recession, a confusing mixture of regulated and unregulated natural gas prices, and restrictions on consumption caused demand to decline (bottoming out at 44 Bcf per day in 1986—more than 25 percent below its peak 14 years earlier). Pipelines that had executed long-term take-or-pay contracts with producers during the shortage years of the 1970s, typically at the "maximum lawful price," found themselves "out of the market." They were obligated to purchase large quantities of natural gas at prices that were higher than end users were willing to pay. Meanwhile prices in spot markets were much lower, reflecting the emerging "gas bubble"—that is, an extended and growing surplus. End users sought to bypass the high-priced, contracted pipeline gas in favor of this lower-priced spot gas, and the results wrought havoc with long-term contracts between natural gas pipelines and existing producers. Ultimately the FERC issued a series of orders that restructured the industry. The final act of this process, the Natural Gas Wellhead Decontrol Act of 1989, provided for the elimination of all price ceilings on natural gas by January 1, 1993.

The Clean Air Act amendments of 1990 and deregulation of power generation during that decade precipitated higher demand for natural gas from the power sector. At the same time, access to federal lands was restricted, and this contributed to the inability of the natural gas industry to meet this growing demand.

Policy Stimulus to Unconventional Natural Gas Development

Unconventional natural gas is not a new supply source. The Marcellus Shale was so named in 1839, and the Jurassic Haynesville Shale of North Louisiana has produced small quantities of natural gas since 1905. But for many years this gas required stimulation techniques that were costly to the point of being uneconomic.

Policy initiatives going back decades played a role in turning unconventional gas into a growing source of supply. The Natural Gas Policy Act of 1978 provided some price relief for "high-cost natural gas"; and two years later tax credits were provided for unconventional natural gas recovery in the Crude Oil Windfall Profits Tax Act of 1980. Indeed it was the Windfall Profits Tax Act that provided the detailed definition of unconventional natural gas most commonly used today:

- natural gas from shale formations with very low permeability
- natural gas from tight sands—similar to conventional reservoirs, but with lower permeability and porosity

*The Fuel Use Act was repealed nine years later in 1987.

- CBM—natural gas found in coal seams

These tax credits were popularly known as "Section 29 credits" in reference to the pertinent section of the Internal Revenue Code. According to the US DOE, unconventional natural gas production responded measurably to the Section 29 credits, rising from less than 0.3 Bcf per day in 1980 to more than 8 Bcf per day in 1990. Growth continued in the 1990s. With the development of the CBM play in the San Juan Basin and the continued growth of tight sands capacity, unconventional gas productive capacity reached about 14 Bcf per day by 2000. But shale gas was only a small fraction of the new unconventional production—just 1 Bcf per day. Most of the unconventional gas was gas from tight formations (almost 9 Bcf per day), followed by CBM (4 Bcf per day). The Section 29 tax credits ceased to be available after 2002, and the continued growth of unconventional natural gas production has not required any measure of fiscal support.

Nevertheless the bulk of North American natural gas production still came from conventional plays. But the conventional natural gas resource base (where access was allowed for drilling) was maturing. As recently as 2006 it appeared that North America was headed for an extended period of tight supplies of natural gas. Prices had risen, but increased drilling failed to bring forth additional supplies as the productivity of new wells declined. Production from conventional plays was declining, and the number of new wells required to maintain a constant level of production had tripled in less than ten years. In order to meet demand, North America seemed destined to import increasing quantities of LNG in what was becoming a more globalized natural gas business.

NATURAL GAS DEVELOPMENT IN CANADA—A SIMILAR TRAJECTORY

The history of Canada's natural gas industry dates back to 1859 in New Brunswick. But it was not until the turn of the twentieth century that the value of natural gas began to be appreciated, with the start of the first commercial natural gas field in Medicine Hat, Alberta. Western Canada would emerge as the nation's natural gas leader. The Western Canada Sedimentary Basin (WCSB), which underlies the provinces of Alberta, British Columbia, Saskatchewan, and parts of Manitoba, produces over 98 percent of the total natural gas in Canada today.

Government intervention in the industry began shortly after the first discoveries. In 1901 the Ontario government banned exports to the neighboring United States as a result of fears that early gas supplies were dwindling. Mineral rights were transferred to provincial control in 1930. In 1959 the Canadian government formed the National Energy Board (NEB) to oversee energy imports and exports, international and interprovincial natural gas and oil pipelines, and resource discoveries in frontier lands not covered under joint federal-provincial jurisdiction.

A great deal of natural gas infrastructure was built in the 1950s as new markets were developing within Canada and the United States—including the NOVA Pipeline (Alberta intraprovincial), Westcoast (connecting British Columbia and the US Pacific Northwest), and the TransCanada Pipeline (linking eastern Canada to the WCSB). However, the energy crisis in the 1970s disrupted growth, as did the ensuing regulation of energy prices in 1975 and the

National Energy Program (NEP, 1980–85). In a period of heightened resource nationalism, the NEP was intended to ensure energy security, provide protection from rising oil prices, and promote Canadian ownership and control in the energy industry. In fact the consequences of the price controls and taxation of natural gas retarded growth in the energy industry in Canada. Not until 1986, when the NEP was dismantled and Canada deregulated natural gas prices, did a new era of natural gas revival begin. The WCSB remained the main producing basin; it responded to the deregulated environment and flourished.

However, in recent years the WCSB began to decline as the basin matured and the costs of sustaining growth increased. Record prices for natural gas between 2005 and 2008 were unable to arrest this decline—particularly in Alberta, where changes in the fiscal regime have been perceived by many producers to have become more restrictive.

But now the Canadian upstream supply industry is undergoing a transformation similar to what has recently occurred in the United States with an increasing focus on the potential of new unconventional gas supplies including CBM and shale gas. The most prospective shale basins are situated in northeastern British Columbia, with others holding potential in Alberta, Ontario, Quebec, and the Maritimes. The addition of shale and other unconventional gas to the Canadian supply mix is expected to allow supply capacity to be maintained or even grown into the future.

INNOVATION DRIVER OF THE SHALE GAS REVOLUTION

What was the driver of the transformation of the indigenous supply outlooks for the United States and Canada? A set of overlapping innovations, integrated in their application, eventually provided the key to unlocking the full potential of unconventional natural gas, most notably the combining of hydraulic fracturing (fraccing) with horizontal drilling. These innovations finally allowed shales to become the dominant component of the unconventional natural gas supply growth—more than 25 years after the passage of the Section 29 tax credits.

The model—and the laboratory—for shale gas development was an increasingly large area of northern Texas known as the Barnett Shale. Mitchell Energy and Development Corporation drilled its first Barnett well in 1981. George P. Mitchell, the chairman of Mitchell Energy, was convinced that the Barnett Shale could be made productive with the right technological approach, and he drove his company to experiment with a variety of fraccing techniques. In 2002 Mitchell Energy was acquired by Devon Energy Corporation, which during 2002–03 began to combine the fraccing with horizontal drilling. Volumes began to climb.

Today the majority of new wells in shale plays are horizontal wells with multiple fracture steps along the horizontal wellbore. Such wells cost more than vertical wells but produce much larger volumes of natural gas and thus reduce the unit costs of development and production. Fraccing has been a customary part of the oil and gas business for many decades, long predating the emergence of unconventional natural gas. More than one million oil and gas wells in the United States have been fracced during the course of their producing lives. This routine operation, when combined with horizontal drilling, allows more recovery of oil and gas while drilling fewer wells—thereby reducing the surface footprint of development. It is this combination that has liberated the natural gas trapped in shale rock.

Table I-1

Resource Assessments: Marcellus Shale

(Tcf)

Date	Agency or Author	Recoverable Gas	Gas in Place
2009	IHS CERA	195–778	
2009	Capozza[1]	516	
2009	Engelder[2]	489	2,445
2009	DOE[3]	262	1,500
2008	IOGA of NY[4]	500	
2008	NCI[5]	34.2	1,500
2008	Engelder & Lash[6]	168	516
2002	USGS[7]	0.8–3.7	

Source: IHS CERA.
1. Capozza, Richard, "Marcellus shale: a modern-day gold rush," *Oil and Gas Journal,* August 1, 2009.
2. Engelder, T., "Marcellus 2008: Report card on the breakout year for gas production in the Appalachian Basin," *Fort Worth Basin Oil and Gas* Magazine, August 2009, pp. 18–22. http://www.fwbog.com/index.php?page=article&article=144
3. US Department of Energy, Modern Shale Gas Development in the United States: A Primer (April 2009), Exhibit 11, page 17. http://fossil.energy.gov/programs/oilgas/publications/naturalgas_general/Shale_Gas_Primer_2009.pdf
4. Independent Oil & Gas Association of New York, The Facts About Natural Gas Exploration of the Marcellus Shale, Home Grown Energy (2008). http://www.marcellusfacts.com/pdf/homegrownenergy.pdf
5. Navigant Consulting, Inc., North American Natural Gas Supply Assessment, prepared for American Clean Skies Foundation (2008), page 17, "NCI Collected Producer Assessments by Play."
6 "Unconventional Natural Gas Reservoir in Pennsylvania Poised to Dramatically Increase US Production," *Science Daily,* January 2008. http://www.sciencedaily.com/releases/2008/01/080117094524.htm
7. Milici, R. C., Ryder, R. T., Swezey, C. S., Charpentier, R. R., Cook, T. R, Crovelli, R. A., Klett, T. R., Pollastro, R. M., and Schenk, C. J., "Assessment of undiscovered oil and gas resources of the Appalachian Basin Province, 2002, US Geological Survey Fact Sheet FS-009-03 (2003), p. 2. http://pubs.usgs.gov/fs/fs-009-03/

THE INCREASED NATURAL GAS RESOURCE COULD CHANGE THE GAME

It seems that estimates of the recoverable resource change on an almost monthly basis as operators report the latest results, driven by new information from appraisals of drilling results as well performance continues to improve. Resource estimates can also vary due to assumptions about the future development path of each play, such as access to land, the number of wells drilled per acre, and future drilling costs. For example, Table I-1 shows how estimates of the resource potential of the Marcellus Shale have increased between 2002 and 2009. IHS CERA's own recoverable resource estimate ranges from a low of 195 Tcf to a high of 778 Tcf for the Marcellus Shale (depending on the drilling density that is eventually achieved).

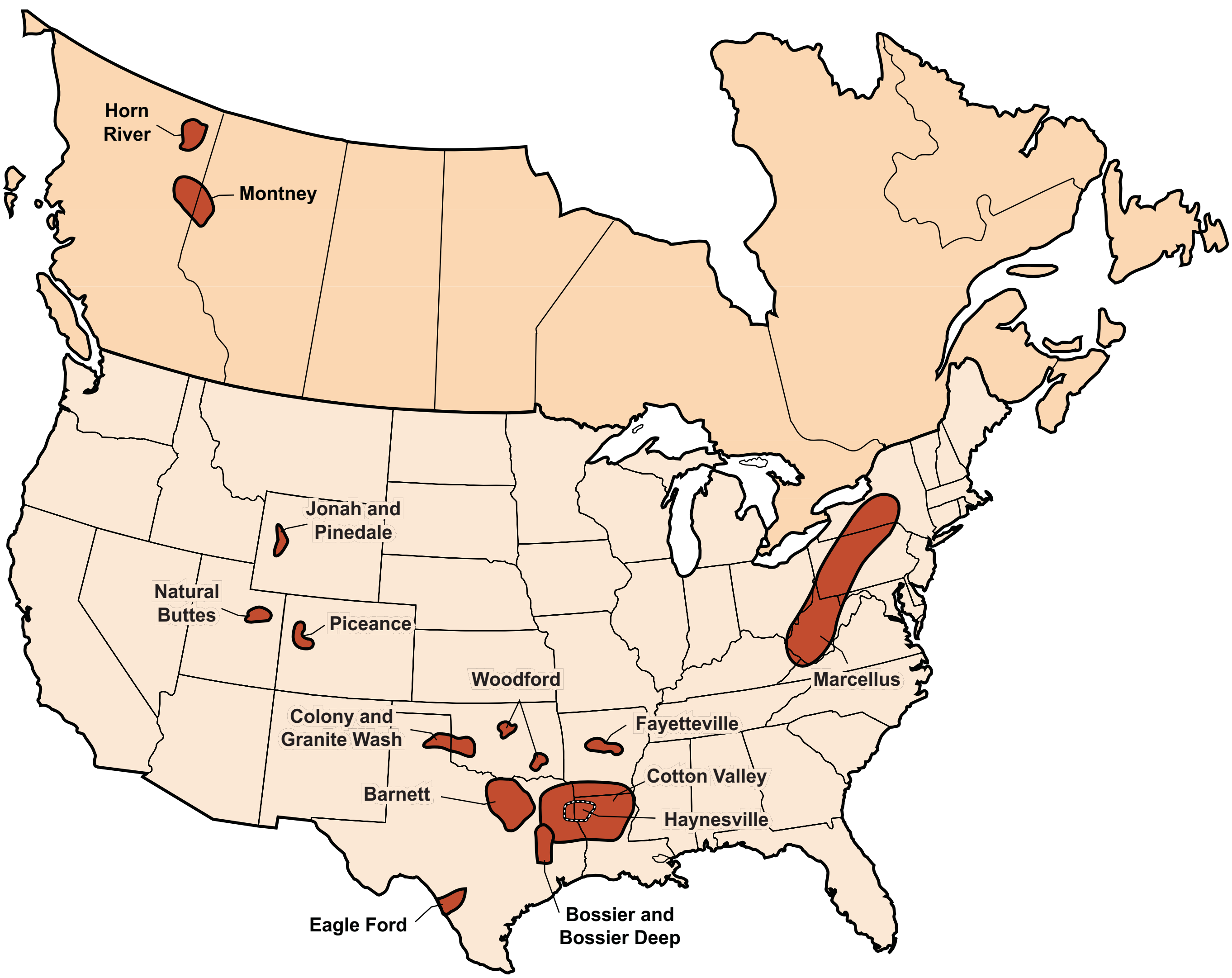
A similar progression of resource upgrades is typical of the other major shale plays.

ABUNDANT, GROWING RESOURCE BASE

What is the potential? To support the research for *Fueling North America's Energy Future,* IHS CERA undertook an in-depth analysis of 17 noteworthy natural gas plays in North America. These consist of eight shale plays—the Haynesville, Eagle Ford, Marcellus, Fayetteville, Woodford, Barnett, Horn River, and Montney Shales that make up the majority of the resource additions. Nine tight sands plays—the Bossier, Deep Bossier, Cotton Valley, Colony Wash, Granite Wash, Jonah, Pinedale, Piceance, and Natural Buttes—were also analyzed, as they have significant resource potential (see Figure I-3). Together these plays represent approximately half of the total estimated resource base for North America (including as yet undiscovered resources) and exceed in volume all the natural gas produced in North America since 1930 (a little over 1,200 Tcf).

Figure I-3

Current North American Unconventional Gas Hot Spots



Source: IHS CERA.
00112-12

The geographic extent of the shale resource is so large that it cannot help but overlap with a variety of other land uses. Significant shale resource potential lies in areas that are off limits to development. Similarly, other areas containing both conventional and unconventional natural gas resources are also restricted. Examples of such restrictions include, or are proposed for,

- urban areas such as Dallas, which lies over part of the Barnett Shale, and Pittsburgh, which lies over part of the Marcellus Shale
- the watershed supplying New York City, which includes portions of the Marcellus Shale in New York State
- certain areas in the Rockies due to environmental concerns regarding topography, wildlife, water, and air quality, among others
- some forest lands, wilderness areas, and national parks

If opened for development, these areas could add significantly to the natural gas resource base. However, our approach in this analysis has been to exclude the vast majority of the potential of these restricted areas from our estimates.

The production potential of these 17 plays is predominantly from shale formations, but the tight sands plays are also significant. IHS CERA estimates a total of 1,658 Tcf of resource from the shale plays and 201 Tcf from the tight sands—a total of 1,859 Tcf of natural gas resource expected to be recoverable from this subset of the North American resource base (see Table I-2).

The IHS CERA analysis distinguished between resources that would be expected to be economically viable at market conditions anticipated during the next 40 years ("commercial" areas) and those that could be technically recovered some day if natural gas prices increased or technological breakthroughs significantly reduced their cost. In assessing their commercial

Table I-2

Gas Resource Estimates by Commerciality and Play Type

	Commercial				Technical	Total Resource
	High	Medium	Low	Total Commercial		
Shale (Tcf)	483	507	405	1,395	263	1,658
Tight sands (Tcf)	36	29	27	92	108	200
Total (Tcf)	520	536	432	1,488	371	1,859
Years of consumption[1]	20.0	20.6	16.6	57.2	14.3	71.5

Source: IHS CERA.
1. At 2009 consumption rate of 26 Tcf per year for US Lower 48 and Canada.

and technical potential, we identified "sweet spots" with the highest commercial potential, "medium commercial" areas, "low commercial" areas, and "technical" areas (where expected ultimate recoveries [EURs] are too low and costs too high to qualify as commercial).

IHS CERA estimates the commercial shale gas resource to be 1,395 Tcf for the eight analyzed shale gas plays in North America. This resource base would, if proved up and developed, be capable of producing at the current rate (26 Tcf per year, or 72 Bcf per day in 2009) for more than 50 years. The results are even more striking when one considers the considerable conventional, tight sand, and CBM natural gas production that would continue to be produced during this period. Including this underlying supply, North American supply could be expected to grow well into the second half of this century, assuming sufficient market demand.

Low Cost of Shale Gas Supply

Because the technology of shale gas production (including horizontal drilling and hydraulic fracturing) permits the recovery of much greater volumes of natural gas per well than is true for many conventional natural gas plays, the shale gas supply can be made available at a lower cost than the current average. Initial production (IP) rates for wells in a shale play can lie in the range of 3 to 15 million cubic feet (MMcf) per day, compared with the average US gas well rate of only 1 MMcf per day.

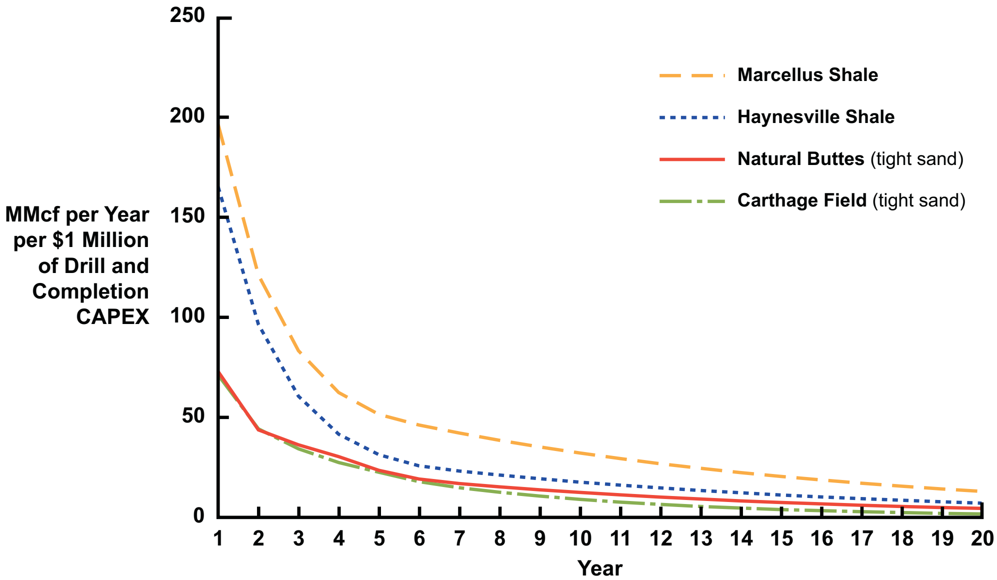
Some fear that these higher IP rates are an illusion because the production from shale gas wells declines rapidly in the first few years and that reserves are overstated because the wells will be exhausted in a few short years. The first part, at least, is valid; shale gas wells (in common with any well that has benefited from fraccing to stimulate initial production) typically have steeper initial decline rates than conventional wells. As the flow performance of the well becomes dominated by the broader reservoir rather than the access to the wellbore provided by the frac treatment, the decline rate subsides. In subsequent years, shale gas wells can exhibit lower decline rates than conventional wells.

Normalizing the performance of shale wells (reporting the production per dollar of well cost) shows that the higher rates of new shale gas wells do indeed suffer a more precipitous decline, but even after three years the shale gas wells are producing more than their traditional counterparts (see Figure I-4). The higher IP rates and higher initial decline rates do not point to reduced reserves because the early production is not at the expense of the longer term.

IHS CERA's analysis indicates that more than 900 Tcf of unconventional natural gas could theoretically be developed and produced if the Henry Hub price were to range between $4 and $6 per MMBtu (see Figure I-5). But in practice shale gas will be developed as part of a broader portfolio including other unconventional natural gas (tight sands and CBM) as well as continued production of conventional resources. Although shale gas is clearly increasing its share in the supply mix, continuing reliance on higher-cost resources will result from practical considerations such as producers' acreage positions; adequacy of the service industry in new areas; and infrastructure, market, and financial constraints. These higher-cost resources will likely define the marginal cost of North American natural gas production.

Figure I-4

Comparative Declines of Shale and Sandstone Plays: Higher Initial Production Rates Not at the Expense of Ultimate Recovery



Source: IHS CERA.
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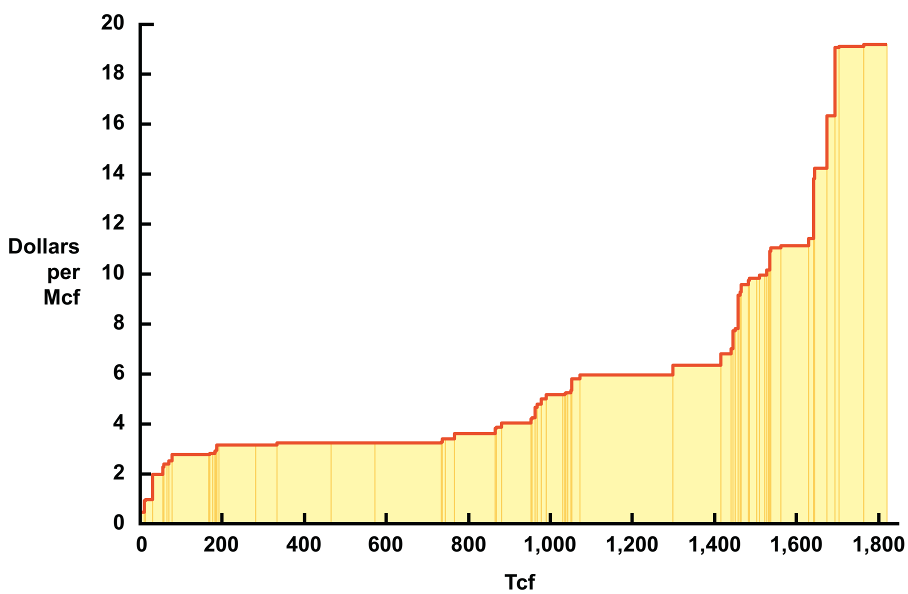
Figure I-5

Breakeven Henry Hub Price for Natural Gas Resources* in Analyzed Plays



Source: IHS CERA.
*Proved, possible, and potential resources.
00112-6

Fewer Rigs Needed to Maintain Supply

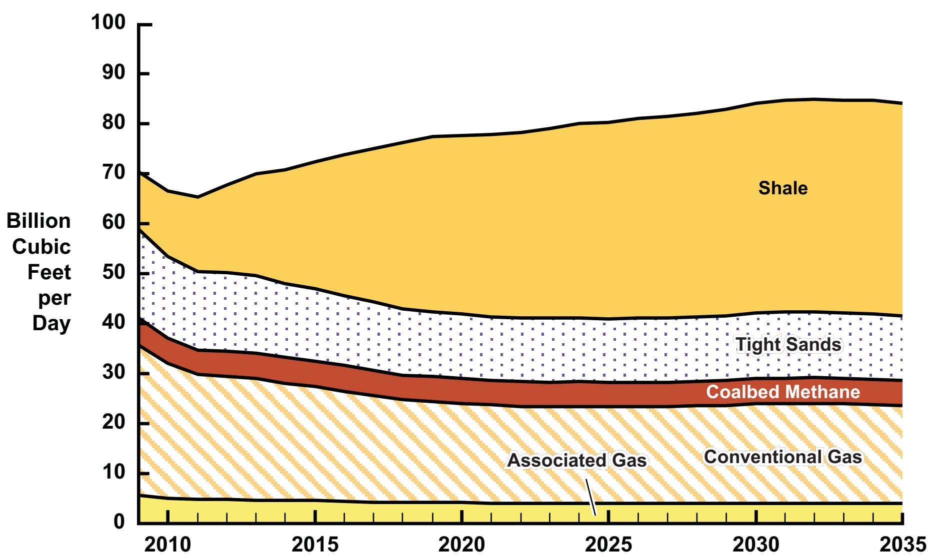
The technologies used in shale gas production have greatly decreased the number of rigs needed to develop a given volume of natural gas. Horizontal drilling, as is common in shale plays, allows a greater volume of natural gas resource to be accessed with a single well. In addition "pad drilling," where multiple wells are drilled from a single site or "well pad," (which reduces the overall land disturbance) allows several horizontal wells to be drilled with a single rig without the need to disassemble and reassemble the rig between wells. Indeed operational efficiencies can be gained by repeating the same operation on multiple wells and drilling a collection of wells in stages—known as "batch" operations. The increased efficiency of the drilling activity requires fewer rigs to drill a given number of shale gas wells and contributes to the continuing reduction in the number of rigs needed to maintain, or even grow, natural gas supply.

THE FUTURE ROLE OF SHALE IN THE NATURAL GAS SUPPLY MIX

As shale gas development becomes more mainstream, it is expected to account for the substantial majority of growth in natural gas supply in North America. Indeed, shale gas alone is expected to grow to more than 50 percent of the supply portfolio by 2030 (see Figure I-6). This supply outlook is predicated on meeting anticipated demand growth from the electric power sector.

Figure I-6

North American Dry Gas Productive Capacity



Source: IHS CERA.
00112-3

The concentration of shale plays in western Canada, the Northeast, the Mid-Continent, and the Gulf Coast makes it likely that we will see a significant change in pipeline and midstream operations in order to move gas from these new supply regions to markets. This may, in turn spur the appraisal of additional shale resources in areas such as the Rockies. The areas that are expected to undergo the fastest growth are the Fayetteville, Marcellus, Haynesville, and Horn River plays along with the Eagle Ford—which may extend significantly into Mexico.

The extent and low cost of the North American shale gas resource pose challenges to other potential sources of natural gas supply, including Arctic natural gas and LNG imports. An Alaska natural gas pipeline, currently proposed at 4.5 Bcf per day of capacity, and/or a 1.5 Bcf per day pipeline from Canada's Mackenzie Delta would have to compete with new

Developing the Resource and Cost Estimates

The analysis for this study made extensive use of data on existing production drawn from the IHS Well and Production data base. Given the rapid pace of development in the leading shale plays, a data-based analysis must necessarily be tempered with experience informed by the very latest reported drilling results. Moreover since a resource estimate is inherently forward looking, it relies, to some degree, on the professional judgment of the team preparing the estimate.

The study assessed the commercial and technical resource potential of several plays. A "play" is a specific geological trend within a subsurface basin thought to contain hydrocarbons. The concentration of hydrocarbons varies within a play, and accordingly so does well performance. Moreover some of the new shale plays, such as the Marcellus Shale, are quite large. Therefore for the purpose of the analysis the plays were subsequently divided into "subplays." These subplays were defined according to criteria such as per-well expected ultimate recovery ranges, technical limits, and geological play features. The result was a collection of subplays with a defined area (square miles) and relatively consistent resource richness (EUR per square mile). Combining these definitions with the factors affecting the development of each play allows conclusions to be drawn about the extent of recoverable natural gas resources. These factors include well economics, the rate of production growth, and aboveground considerations (such as proximity to residential developments, access to water supplies, and infrastructure).

To estimate costs, well parameters for each play—such as type of well (vertical, directional, or horizontal), total depth, drilling days, number of casing strings, depth and diameter of each casing string, and whether production tubing is installed—were obtained from IHS data. Based on these play-specific parameters, costs were estimated using cost information from the IHS QUE$TOR cost-estimating system and analysis from IHS CERA's Cost and Technology group.

Future well costs were projected for each play by escalating individual cost components (surface equipment, subsurface equipment, completion, consumables, drilling rig, drill services, engineering and project management, freight, site preparation, and overhead).

Full-cycle unit costs in dollars per thousand cubic feet of gas were calculated by finding the breakeven wellhead price at which the "typical" well in each play yields a 10 percent return on investment after royalty, depreciation and depletion, severance taxes, and the hypothetical corporate income taxes attributable to the well. The average wellhead breakeven price from each play was then adjusted by the basis differential to Henry Hub (using the average 2009 basis from the pricing point nearest the play) to calculate the Henry Hub price that corresponds to the breakeven wellhead price.

natural gas supplies from the Horn River and Montney plays in British Columbia if the gas is to enter the Canadian or US lower-48 markets—where the gas would also have to compete with gas from the numerous shale plays in the Lower 48. There would be some ramifications for Alberta's natural gas industry and for North America's natural gas industry as a whole if more than 5 Bcf per day of new Arctic supply were to make its way into a likely well-supplied North American market.

But the Alaska and Mackenzie Delta natural gas pipelines have been years in the planning, and neither is likely to be completed before 2020. Over the expected 40- to 50-year lives of these projects, they will be operating through many different market environments, and such long-lived assets have a dynamic of their own.

Furthermore the shale gas revolution has altered the prospects for LNG imports into North America. Until 2007 it had been widely expected that increasing volumes of imported LNG would be required within a few years. North America was expected to join the global gas market and to pay global prices, competitive with oil-linked prices prevalent in other markets, in order to attract LNG supplies. Instead it now seems that LNG imports into North America will be a matter of choice rather than necessity. The effects of this shift will be felt throughout the globalized natural gas industry—among other things, redirecting to Europe, or farther afield, LNG cargoes that would otherwise have gone to the United States.

CHAPTER II: ENVIRONMENTAL ISSUES ASSOCIATED WITH SHALE GAS DEVELOPMENT

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- Natural gas has a lower carbon footprint—about half that of coal—and results in negligible sulfur dioxide (SO_2), nitrogen oxides (NO_X), mercury, and particulate emissions compared with other fossil fuels.
- The local impacts—land disruption, air quality, and noise disturbance—occur during the drilling and completion phase (two or three months per well) rather than the production phase (20 to 40 years). Drilling multiple wells from a single location will extend the initial period of disturbance in the immediate vicinity but will reduce the area/extent of the overall disturbance.
- Water has emerged as the most important environmental issue with unconventional natural gas, in terms of both fraccing and "produced water."
- A comprehensive regulatory framework for well construction and water management is already in place, with the objective of protecting drinking water supplies.
- Deeper dialogue between industry and other stakeholders is required, as well as greater transparency and understanding of the technology, geology, and the current highly regulated system of water management.

The greatest attraction of natural gas from an environmental perspective is that it results in the lowest carbon dioxide (CO_2) emissions of any fossil fuel. For this reason it has significant potential to address global climate change concerns. All types of energy production and use involve trade-offs among local environmental impacts, economic development, and impacts on the wider environment or climate. Shale gas resources are no exception and raise both positive and negative issues for the environment and local communities. Regulations, mostly at the state and local levels, strive to reduce and mitigate the environmental consequences of shale gas development.

The positive environmental attributes of shale gas are many. Natural gas emits as much as 50 percent less CO_2 than coal when used to generate electricity. The climate change benefits of natural gas get the most attention, but emissions of local air pollutants also decrease, including SO_2, NO_X, mercury, and particulates. These benefits of natural gas accrue to those at the consumer end of the value chain—end users of natural gas. With greenhouse gas reductions the benefit is global.

What are the impacts of shale gas development at the upstream end of the value chain—where the gas is produced? From an economic point of view, communities stand to gain as natural gas development generates jobs and revenue in the local economy. Leases for drilling rights generally provide landowners with royalties, rental payments, and bonuses. Jobs are created as roads are built and land cleared for drilling, production, and pipelines and as service companies and operators build local headquarters and field offices. IHS Global Insight has estimated that at the national level, the overall natural gas industry employed

State Regulation of Natural Gas Development

The State of Kansas provides an example of the regulatory process that governs natural gas production. Kansas has been an oil and gas producing state for more than 120 years. The Kansas Corporation Commission Oil & Gas Conservation Division manages oil and gas regulation. The permitting regulations are designed to protect the environment and local residents during well construction, development, and production.

Kansas requires a permit for each well drilled, regardless of its purpose. All drillers must be licensed by the state. The process of hydraulic fracturing is regulated along with all other drilling activities. Operators do not have to get a separate permit for well fraccing or horizontal drilling. However, the well completion affidavit asks for information on any fraccing fluids used. The state collects information on the types of fluids but not the specific formula of the fraccing fluid.

The focus of state regulation is the protection of groundwater resources, and the mechanism for this protection is proper well construction. Wells must be designed to protect all freshwater aquifers, and the well casing must extend at least 50 feet below the deepest potential source of drinking water. The state requires cement bond logs, and in some cases a state official must be on site during the well cementing process to ensure that the well is structurally sound. The depth of the gas plays in Kansas provides an additional barrier to contamination of aquifers that could be used for drinking water.

550,000 workers in 2008 and was responsible for the creation of an additional 2.4 million jobs in supporting industries, adding over $400 billion to the US economy. In Canada the oil and gas industry directly and indirectly supports more than 600,000 jobs.*

On the other hand, shale gas development can be detrimental to the local environment, especially during the site preparation, drilling, and fracturing processes. These impacts are concentrated mostly in the immediate area of development and are generally temporary. For example land disturbance and nuisance dust are sometimes issues during site preparation, and noise and diesel exhaust occur throughout the preparation, drilling, and fracturing processes. Environmental impacts are minimal once the well is in the production phase.

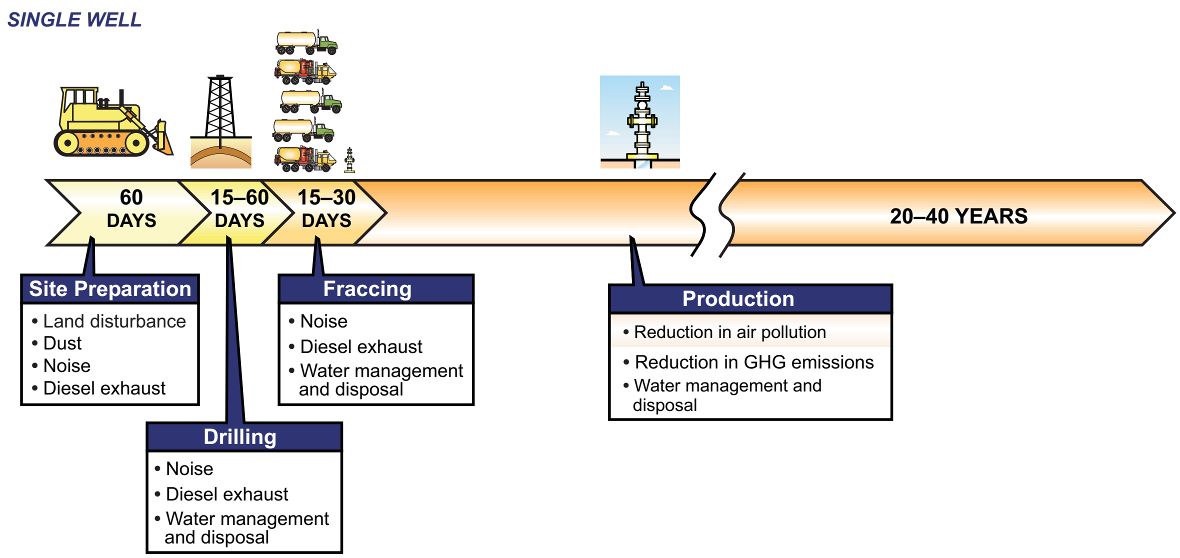
The shale gas development process is regulated at the state and local levels. Prior to drilling operators must obtain a permit that generally includes approval of the well location, well design, and plan for restoring the location after drilling is complete. Environmental impact statements review the potential environmental impacts and establish plans to mitigate them.

The process of bringing a well into production, where most environmental impacts occur, can take a few weeks for a single well (see Figure II-1). For multiple wells on a single pad the process can take up to a year and a half. However, once the well is in production, it produces natural gas for 20 to 40 years. The up-front local disturbances are relatively short-lived, but the long-term benefits of using cleaner-burning natural gas continue for decades. Moreover the higher productivity typical of shale gas wells means that fewer wells need to

*Source: IHS Global Insight, *The Contributions of the Natural Gas Industry to the U.S. National and State Economies* and *The Contributions of the Natural Gas Industry to the Canadian National and Provincial Economies*, both prepared for America's Natural Gas Alliance, 2009.

Figure II-1

Timeline for Shale Gas Development and Production



Source: IHS CERA.
00112-11

be drilled to meet a given level of demand. As a result the adverse environmental impacts of shale gas production are in many ways less than those associated with conventional gas production.

Even though the detrimental environmental impacts of shale gas are short-lived compared to the benefits, the local environmental effects of shale gas development are raising more attention as development moves into areas that have not seen significant oil and gas production before (or at least in many decades, as the US oil and gas industry was founded in western Pennsylvania) or that are closer to population centers. Figure II-2 shows the locations of shale gas plays in relation to population density.

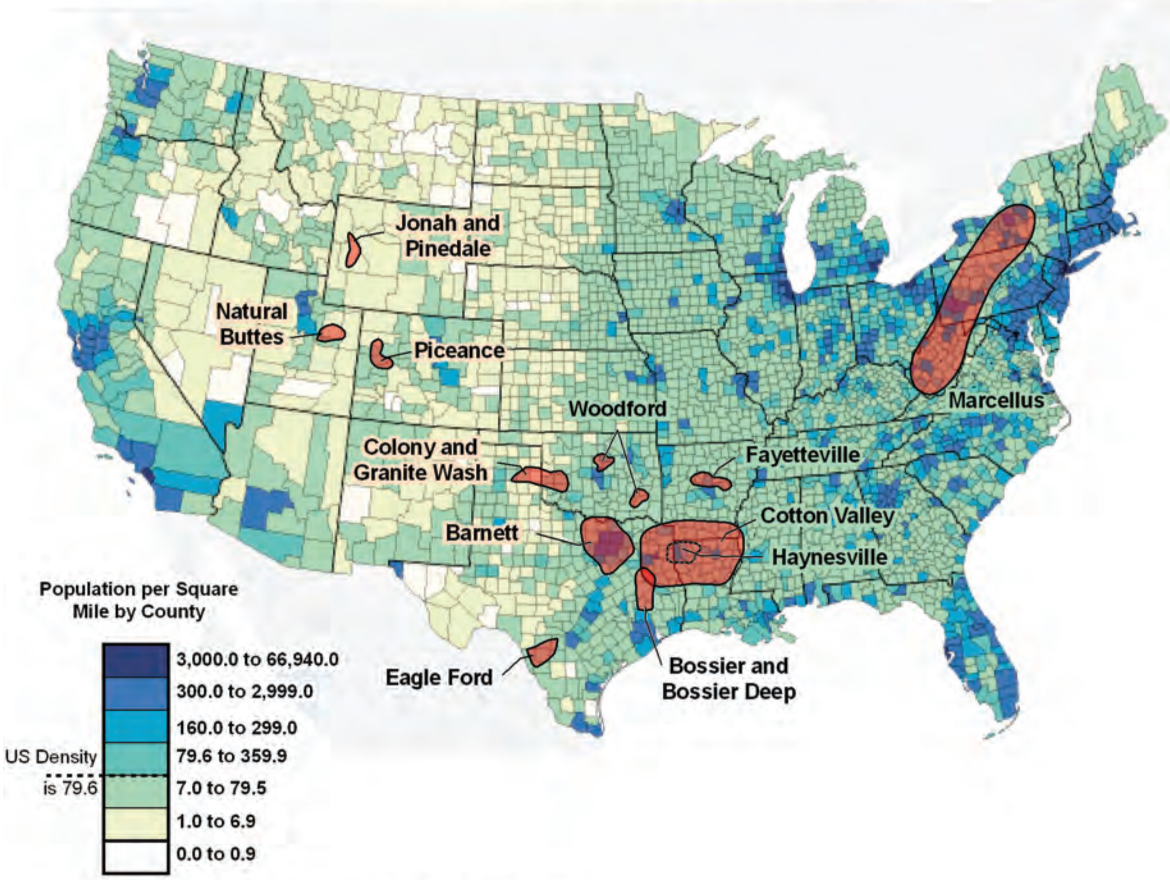
Water has emerged as the most contentious environmental issue associated with shale gas development. Thus, the remainder of this section focuses on water issues. Water use and the potential for water contamination are issues associated with all oil and gas production, including shale gas. Unlike the other potential negative effects of shale gas production, water impacts, if not properly handled, have the potential to cause effects beyond the immediate area of production.

WATER USE IN NATURAL GAS PRODUCTION

Water is a critical ingredient in natural gas development, particularly for wells that rely on hydraulic fracturing. In the aggregate the water required for shale gas development does not appear to be a major obstacle. If 10,000 shale gas wells are drilled each year, and if

Figure II-2

Shale Gas Plays and Population Density in the United States



Source: IHS CERA and US Census Bureau, *Census 2000.*
00112-13

each well uses 4 million gallons of water, shale gas development would require 40 billion gallons of water per year. This is less than 0.03 percent of total water use in the United States in 2005—410 billion gallons a day, or 150 trillion gallons per year, according to the US Geological Survey.* Nevertheless water is very much a local issue, and whether local water supplies are adequate to support drilling may vary widely across localities. The 2 to 4 million gallons of water required to drill and complete a well must be furnished in a short time frame, which can pose challenges for local water availability.

Shale gas production is considerably less water intensive than other types of energy production. Ten times as much water is used to produce the equivalent amount of energy from coal, and ethanol production can use as much as a thousand times more water to yield the same amount of energy.**

*US Geological Survey, *Estimated Use of Water in the United States in 2005,* October 2009.
**See the report *Thirsty Energy: Water and Energy in the 21st Century,* produced by the World Economic Forum and IHS CERA, February 2009.

PROTECTION OF DRINKING WATER SUPPLIES

Of the potential environmental impacts of shale gas development, none has raised more public concern than the fear of contaminated drinking water supplies. The City of New York has asked the state to declare off limits those regions of the Marcellus Shale that underlie the New York City watershed. Regulators in some states are investigating reports of drinking water wells that have been contaminated by chemicals of undetermined origin, concerned that these may be related to oil and gas development. Congress has instructed the Environmental Protection Agency (EPA) to conduct a study of the potential for hydraulic fracturing to contaminate underground sources of drinking water, and bills have been introduced in Congress that would require EPA to regulate hydraulic fracturing under the Safe Drinking Water Act (SDWA). The nearly identical bills are HR 2766, introduced by Representative Diana DeGette (D-Colorado), and S 1215, introduced by Senator Robert Casey (D-Pennsylvania).

The focus of this controversy is on the hydraulic fracturing process and its potential to contaminate drinking water aquifers. However, the consensus among geologists, petroleum engineers, and government reports is that such an event is highly improbable. Shale gas deposits are typically located several thousand feet below the deepest potential underground source of drinking water, and the low permeability of shale rock and other intervening formations restricts upward flow of fraccing fluids into drinking water aquifers (see Figure II-3).* A properly installed well includes steel casing surrounded by concrete to separate the well from freshwater aquifers above the shale gas zone. The surface casing extends at least 50 to 100 feet below the deepest potential source of drinking water—the required depth is established by regulations in each state. Regulatory inspections ensure that the well is structurally sound before fracturing occurs.

Although geology and proper well installation make water contamination from hydraulic fracturing very unlikely, there is a second set of issues. The storage, use, and waste disposal associated with chemicals used for natural gas production and produced water are potential sources of water contamination. In fact all oil and gas operations—not just those that involve hydraulic fracturing—involve use and disposal of liquids that must be managed properly. Areas of particular attention include preventing surface spills that could run off into waterways and into the ground, installing wells properly to prevent contaminants from entering underground sources of drinking water through breaches in the well casing, and properly disposing of liquids produced with the natural gas. Concerns were heightened last September when one natural gas company was responsible for three surface spills in one week at its drill sites in northeastern Pennsylvania. State regulators required the company to cease operations temporarily until it had developed a satisfactory plan for managing wastes and potential contaminants. These spills are an example of the potential for contamination not directly related to the fraccing taking place deep underground.

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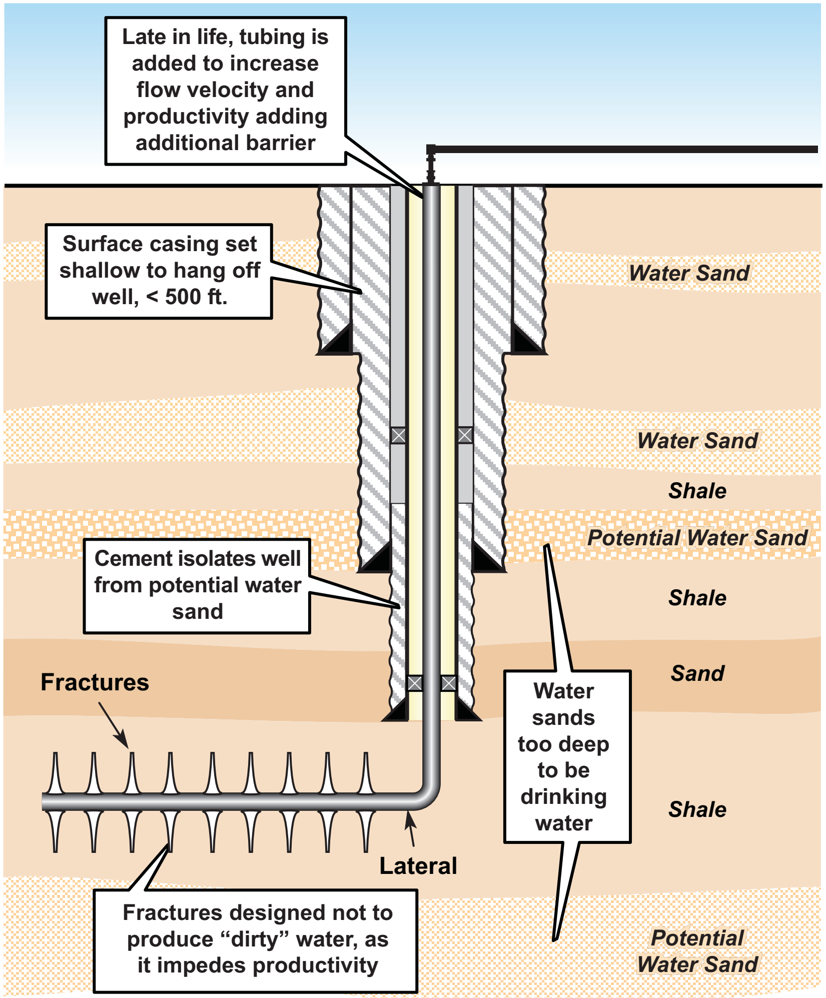
*See for example, US Department of Energy, Office of Fossil Energy, National Energy Technology Laboratory, *Modern Shale Gas Development in the United States: A Primer,* April 2009, and US Congressional Research Service, *Natural Gas Drilling in the Marcellus Shale,* September 9, 2009.

Figure II-3

Schematic of a Shale Well



Source: IHS CERA.
90802-10

As for what constitutes appropriate regulatory safeguards, there is a divergence of opinion. The natural gas industry and regulators from natural gas–producing states argue that local environmental issues are best handled at the state and local levels where regulators are familiar with the environment (including the geology and hydrology) specific to their location. They point to the history of safe oil and gas drilling as evidence that these practices and regulations are sound and effective. Those who fear that hydraulic fracturing might contaminate drinking water aquifers tend to support stronger regulation at the federal level. This controversy needs to be understood in the historical context, and that goes back to the passage of the SDWA during the era of rising environmental consciousness in the 1970s.

Produced Water

One of the most environmentally sensitive parts of the natural gas production process involves the disposal of the significant volumes of water and other fluids that are brought up with natural gas during the production process. This "produced water" includes water and brines naturally occurring in the formation as well as flowback of fraccing fluids. Produced water must be dealt with in all natural gas (and oil) production, although of course produced water from wells that have not been fracced will not contain fraccing fluids. The US Department of Energy estimates that 20 billion barrels of produced water are generated each year from oil and gas operations in the United States. Produced water may be disposed of underground in two ways—it can be injected into oil- or gas-producing wells to maintain reservoir pressure or it can be injected into deep wells for disposal. More than 98 percent of onshore produced water in the United States is disposed underground, and both underground disposal options are federally regulated under the SDWA. Water not disposed underground is disposed through evaporation or land application, and water treatment facilities for produced water are becoming more advanced and more common. Treatment of produced water has also become a focus for research and innovation.

A Brief History of the Safe Drinking Water Act and Hydraulic Fracturing

Congress passed the SDWA in 1974, authorizing EPA to regulate the nation's public drinking water supplies to ensure that they pose no risk to public health. SDWA regulation applies to all public water systems. Private wells and bottled water are exempt. EPA establishes national health–based standards for drinking water quality, such as maximum allowable levels of contaminants. These standards are then implemented by state and local regulatory agencies under EPA oversight.

In addition to regulating drinking water treatment, the SDWA also focuses upstream on sources of drinking water. The SDWA's Underground Injection Control Program regulates the injection of fluids into underground formations. Such fluids include not only agricultural, municipal, and industrial wastes but also fluids injected for purposes of enhanced oil recovery and liquid hydrocarbons injected into storage wells (such as the salt caverns at the Strategic Petroleum Reserve). EPA has established five classes of underground injection wells for purposes of regulation. Class II wells are those drilled for injections associated with oil and gas production.

EPA delegates primary enforcement authority (known as "primacy") to states that can demonstrate that state regulations meet or exceed the national standards set by EPA. Of the 30 members of the Interstate Oil and Gas Compact Commission (IOGCC), 24 have primacy over Class II (oil- and gas-related) injection wells (see Table II-1).

From 1974, when SDWA was enacted, through 1997 EPA did not consider hydraulic fracturing to be underground injection for purposes of SDWA enforcement and did not regulate the practice. In 1994 the Legal Environmental Assistance Foundation (LEAF) challenged EPA's definition of underground injection, stating that hydraulic fracturing should be regulated under EPA's Class II well designation. LEAF acted on behalf of a family in Alabama that argued that hydraulic fracturing of a shallow coalbed methane (CBM) well had contaminated a water well on their property. LEAF requested that EPA withdraw Alabama's primacy over

Table II-1

IOGCC States and Primacy over Class II Injection Wells

State Primacy	States Without Primacy
Alabama	Arizona
Alaska	Kentucky
Arkansas	Michigan
California	New York
Colorado	Pennsylvania
Florida	Virginia
Illinois	
Indiana	
Kansas	
Louisiana	
Maryland	
Mississippi	
Montana	
Nebraska	
Nevada	
New Mexico	
North Dakota	
Ohio	
Oklahoma	
South Dakota	
Texas	
Utah	
West Virginia	
Wyoming	

Source: US Environmental Protection Agency.

Class II injection wells until the state included hydraulic fracturing as a Class II injection activity. In 1997 the Eleventh Circuit of the United States Court of Appeals agreed with LEAF's argument, and hydraulic fracturing of CBM wells was added to the underground injection control program in the state of Alabama. However, the court ruling did not apply in other states, leaving Alabama as the only state in which hydraulic fracturing was covered by the SDWA.

Congress clarified this unusual situation when it included a provision in the Energy Policy Act of 2005 that specifically removed hydraulic fracturing from the definition of underground injection activities subject to regulation under the SDWA. The DeGette and Casey bills currently pending in Congress would reverse this provision.

Disclosure of Chemical Constituents of Fraccing Fluids

In addition to bringing fraccing under the purview of the SDWA, the DeGette and Casey bills would require companies to disclose the "chemical constituents but not the proprietary chemical formulas" of the materials used in the fracturing process to the state or EPA (whichever has primacy over Class II wells). The state or EPA would in turn be required to make this information available to the public via the Internet.

Additionally the bills would require the disclosure of the exact chemical formula if necessary in a medical emergency involving fraccing fluids. A confidentiality agreement is allowed under these circumstances. This portion of the bills arises out of concern that testing drinking water sources for evidence of contamination is difficult without knowing what components to test for. Concerns have also been raised that the material safety data sheets (required by the Occupational Safety and Health Administration) for components of fraccing fluid may not provide adequate information to treat workers or others who might be harmed in the event of an accident.

Several states already require disclosure of the chemical constituents of fraccing fluid prior to issuing a drilling permit. Nevertheless the disclosure of the chemical formulas used to mix the fraccing fluids remains contentious. Service companies have resisted full disclosure because they see these proprietary formulas as a source of competitive advantage.

THE DEBATE CONTINUES

Efforts to apply more stringent regulation of hydraulic fracturing seem to have greatest traction in states that have not previously had significant natural gas production but now have the prospect of rapid development of their shale gas resources. Many natural gas companies view these efforts as an attempt not to regulate but to prohibit hydraulic fracturing and severely limit shale gas production. They argue that, even if not the intent, more unnecessary and cumbersome regulation on top of existing regulation would increase costs and generate delays and uncertainties, and thus constrain and thwart the development of unconventional natural gas.

Most oil- and gas-producing states have long experience with hydraulic fracturing, which has been in use commercially since 1949. Hydraulic fracturing has always been regulated at the state level by the agencies that regulate all natural gas production in the state. At present there is no evidence that liquids used for hydraulic fracturing of deep shales can migrate upward to contaminate drinking water aquifers, and there are strong geological arguments to the contrary. However, the disposal of wastes associated with hydraulic fracturing must be properly managed and regulated, as is the case for all other wastes from natural gas production. To the extent that wastes from hydraulic fracturing are disposed of through injection into underground wells, they are already covered under the SDWA.

An EPA official has stated that little would change if hydraulic fracturing were to become federally regulated under the SDWA.* States that already have primacy over Class II injection wells would likely be granted primacy to regulate hydraulic fracturing as well, using regulations tailored to each state's conditions. However, several states with substantial shale gas resources, including Pennsylvania and New York, do not have primacy over the SDWA underground injection program. Representative DeGette, the sponsor of the House bill to bring hydraulic fracturing under EPA jurisdiction, recently said, "I support hydraulic fracturing. My bill would not make it illegal or impractical. It simply would require disclosure of ingredients in an emergency situation while protecting proprietary information.** Representative Edward Markey (D-Massachusetts), Chairman of the House Subcommittee on Energy and Environment, affirmed in a recent hearing that there is "no secret plot" to shut down unconventional natural gas development.***

Oil and gas operations are widespread throughout North America, and drinking water supplies have been appropriately safeguarded from contamination from these activities for many years. This suggests that the risks can be managed and that shale gas development can proceed safely, with proper industry management and regulatory safeguards in place. These issues will be better understood and handled through collaboration, research, and transparency, and with an understanding of the current highly regulated system of water management.

*Ian Talley, "EPA Official: State Regulators Doing Fine on Hydrofracking" *Dow Jones Newswires*, February 15, 2010.
**Nick Snow, "'Fracing' Dominates ExxonMobil-XTO Merger Hearing," *Oil and Gas Journal,* February 1, 2010.
***Ibid.

CHAPTER III: NEW MARKET SUPPLY DYNAMICS

CHAPTER III: NEW MARKET SUPPLY DYNAMICS

- Price spikes for natural gas are of particular concern to electric power generators and other large end users.
- Volatility and price variations are essential mechanisms that send signals to consumers and suppliers to balance the market. The extremes, however, can be destabilizing with very adverse results—and thus the need for "shock absorbers" to reduce the impact of hurricanes or other events that might temporarily disrupt supplies.
- The newfound expansion of unconventional gas, combined with the expansion of LNG import facilities in the United States and Canada and increased storage, has introduced new supply shock absorbers to respond to disruptions and market imbalances.
- Past experience of natural gas prices raises a question among large users as to whether relatively more stable prices are at hand, as opposed to the bottom of a cycle. As the giant new shale gas plays are brought into production, end-user confidence in the long-term sustainability of shale gas supply will likely grow.

The abundance and relative low cost of the natural gas resource base have transformative implications for North American natural gas markets. Most significantly the virtual certainty that North America will not have to compete globally for natural gas supplies means that domestic natural gas prices will be determined on the basis of domestic supply and demand under normal circumstances. As a result, longer term natural gas prices need not rise to compete for LNG supplies at oil-linked prices which are prevalent in markets in Europe and Asia. Further, the scale of the resource additions suggests that the shale gas revolution is not just another phase of the familiar boom-bust natural gas investment cycle, with prices declining for a few years followed by rapid increases as more costly conventional resources are explored and developed.

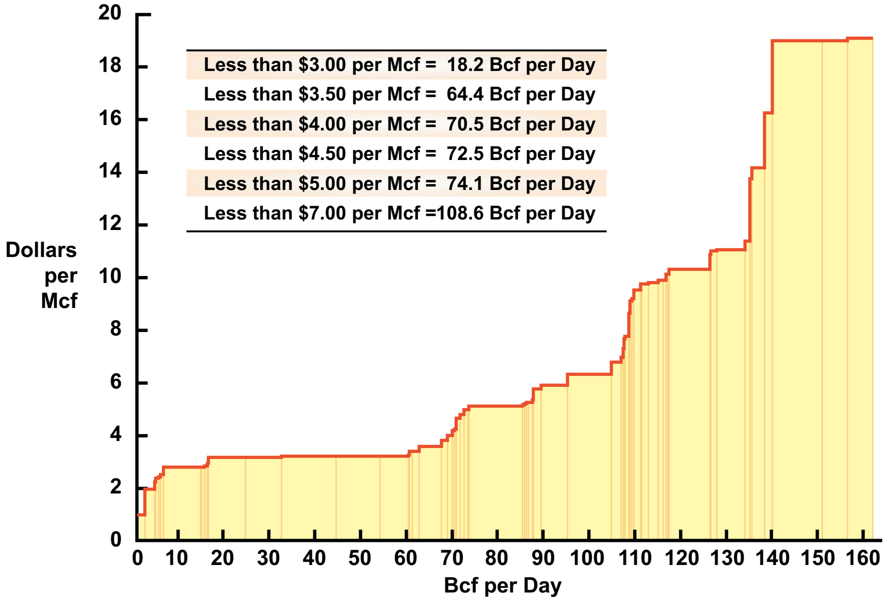
Based on experience, a prevalent anxiety among users about natural gas concerns the lack of "shock absorbers" in the supply system. This lack makes the market vulnerable to demand increases, creating high and protracted price increases that undermine investment by utilities and other end users as well damaging basic confidence in the market. But the advent of shale gas brings on a major new shock absorber—an abundant supply source that can respond relatively quickly to changes in demand. Combined with expansion of LNG regasification and natural gas storage capacity, shale gas means that the natural gas market will now have a more complete set of shock absorbers to help keep the market in balance. These shock absorbers will not, however, prevent short-term event-driven volatility.

ROBUST SUPPLY FOR A WIDE RANGE OF DEMAND LEVELS

The shale gas production process has been described as akin to a manufacturing process in which a well is drilled into a known resource and natural gas is produced with little or no exploration risk. As discussed in Chapter I, the dramatic expansion of the supply cost curve allows a wider range of demand growth scenarios to be met without necessitating a significant increase in the natural gas price (see Figure III-1). When added to the underlying

Figure III-1

Breakeven Henry Hub Price for Productive Capacity* of Analyzed Plays



Source: IHS CERA.
*Forty years of plateau proved, possible, and potential productive capacity.
00112-14

portfolio of conventional natural gas, just the 17 plays that we analyzed could themselves expand supply significantly without forcing more expensive sources of supply onto the margin and driving up natural gas prices.

Furthermore, because of the lower cost of shale gas resources, the trend in natural gas prices is likely to be lower, on average, than either the prices that have prevailed for the past five years ($7.05 per MMBtu) or the prices that would prevail in the future if the shale gas resource were unavailable. In fact the robust prospects for shale gas will help to stabilize long-term natural gas markets.

This cost picture and the price outlook would be different for a period of time if the underlying rate of growth for natural gas demand were to increase suddenly (perhaps in response to new policy requirements that significantly favored or mandated consumption of natural gas). This would likely stress the supply system for a time, leading to inflation in gas services and equipment, which could drive up costs. Eventually the market would rebalance, with additional supplies being produced to meet the added demand; but with costs now at a higher level, the market price would likely be higher as well, until such time as costs came down.

Nor will the shale gas resource eliminate daily and cyclical price fluctuations. These price fluctuations are essential to the functioning of the market, as they provide the vital signals to market participants that allow the system to balance. Short-term imbalances generally arise from weather events—blizzards or heat waves that affect demand for heating and cooling, or hurricanes that disrupt offshore natural gas production. A longer-term change in demand might arise from new oil sands projects or new gas-fired power plants being commissioned. Any price hike resulting from this type of demand addition would probably invoke a supply response over a period of several months.

Natural gas prices are also volatile by virtue of their role in electric power generation. Demand for natural gas to provide peak and intermediate-load electric power will be more volatile than demand for base-load power generation fuels. Natural gas prices will therefore continue to be volatile because even if natural gas takes on a greater role as base-load generation, it will not shed its role in peaking and cycling plants. Price volatility resulting from these temporary, short-term imbalances can be managed through hedging and trading.

NEW SUPPLY SHOCK ABSORBERS

In the past the market's shock absorbers were limited to a time frame of hours and days (storage and line pack), at one end of the spectrum, and years (new infrastructure) at the other end. From 2000 through 2007, and even in the late 1990s, the declining productivity of individual wells and an insufficient number of drilling rigs meant that, for many years, producers could not generate growth through the drill bit. There was a large window of exposure between these two extremes of days and years.

The North American market slowly turned to LNG, but the development of LNG facilities involves a multiyear timeline. Today the development of a global LNG market (and the large increase in regasification capacity at import terminals in the United States) allied with an abundant indigenous natural gas resource base that has already demonstrated its flexibility have added shock absorbers that respond in time frames of weeks and months, respectively. These two sources of supply response help to fill the gap.

Thus the portfolio of market mechanisms to respond to price signals is more complete than in the past.

Daily and Seasonal Fluctuations

Daily fluctuations in natural gas prices will continue to be driven by daily variations in demand and the limitations of wellhead supply and pipeline infrastructure in responding immediately to these variations. Daily demand fluctuations are generally a function of weather, as well as the typically higher demand on week days than on weekends. Variations in power sector natural gas demand follow similar patterns, with the added impact of periodic outages of base-load nuclear and coal generation, often replaced by natural gas–fired generation. Natural gas supply disruptions such as wellhead freeze-offs of production, weather events, or unexpected outages of pipelines or processing plants can also cause fluctuations in daily natural gas prices.

On a cyclical and seasonal basis natural gas prices will continue to fluctuate as storage inventories vary above and below average levels during the course of the year. The drivers of cyclical fluctuations include winters (or summers) that are colder (warmer) than normal. Furthermore economic booms and recessions will continue to provide cyclicality in natural gas prices as for energy prices generally.

Additions to storage capacity in recent years have helped to reduce daily and cyclical price fluctuations. One indication of this effect is that during 2000–09 the trend in daily natural gas price fluctuations remained flat, even though weather-sensitive natural gas demand from the power sector increased from 23 percent of total natural gas demand in 2000 to 31 percent in 2009.

Weekly Fluctuations

Location-specific demand disruptions of more than a few days' duration—such as outages of major power plants that are not fired with natural gas—should be expected. However, it is in response to the unpredictable consequences of such events that the benefit of the new shock absorbers in the market will be felt.

The build-out of LNG regasification capacity in recent years, together with the greater array of flexible LNG supplies that can be diverted to the markets that most need them on short notice, has increased the ability to respond to weekly price fluctuations. The option to import flexible LNG supplies until domestic production responds to prices can help dampen such price fluctuations. By the end of 2011 North America will have 17.8 billion cubic feet (Bcf) per day of regasification capacity, of which only 3 Bcf per day is expected to be used (at a monthly peak).

Monthly Fluctuations

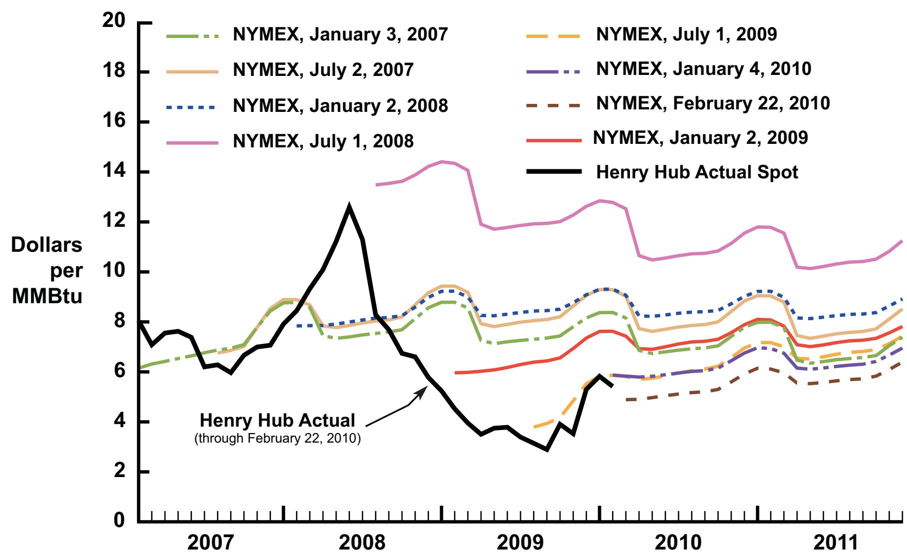
The new shale gas resource base holds the potential to address price fluctuations of a more fundamental nature. First as production moves to the onshore shale gas resource, less reliance on Gulf of Mexico natural gas supplies will reduce the vulnerability of supplies to hurricane outages. Gulf of Mexico production declined from 10.8 Bcf per day in 2004 to 6.4 Bcf per day in 2008 and is projected to continue to decline to 4.1 Bcf per day by 2020.

In addition the "manufacturing" nature of shale gas development has shortened the lead times between a decision to drill and the realization of new natural gas production. Gas producers can ramp up investment more quickly in response to higher natural gas prices, thus dampening the magnitude and/or duration of price spikes. Indeed the 7 Bcf per day increase in natural gas production from January 2007 to July 2008 was the largest 18-month increase since 1990.

If natural gas prices are high enough to justify additional drilling and completion activity, then a wide range of market participants will more than likely respond. It may not even be necessary for "spot" prices to be high enough to justify this activity. Any expectation of future shortages will lead to higher prices on the futures market. As occurred in 2009, drilling activity was maintained even as spot prices fell because companies were able to hedge those price risks and protect the economic return of their investments (see Figure III-2).

Figure III-2

Forward Sales by Producers Providing Cash Flow to Sustain Drilling



Source: IHS CERA.
00112-32

The Long Term

Major projects will require lead times of several years to come to fruition. A decision to develop a new LNG liquefaction and export facility will not provide gas supply for about a decade from the start of feasibility studies. The Alaska Gas Pipeline has been years in the planning and is unlikely to be completed before the end of this decade. However, in response to appropriate price signals, such major infrastructure projects will be financed and built.

The combination of these shock absorbers results in an outlook for natural gas prices that continues to include volatility and cyclicality. But with the changes in the resource base and the LNG infrastructure, response time to market imbalances has been shortened. The size and accessibility of the shale gas resource base will provide some protection against the usual causes of long-term, secular changes in the natural gas price. There will always be periods when supply and demand do not balance properly, but in the past there was little opportunity for rebalancing prices between the effects of storage withdrawals and injection (measured in days) and assembly of major capital projects (measured in years or decades).

The globalization of the LNG business and the advent of the shale gas "manufacturing business" have filled in the gaps in the shock absorbers and created a new environment. As these new developments in the natural gas industry are proved out over the next several years, consumers may become more comfortable taking the position that choosing natural gas does not expose them to an unreasonable market risk during the life of their projects.

CHAPTER IV: NORTH AMERICAN NATURAL GAS DEMAND

CHAPTER IV: NORTH AMERICAN NATURAL GAS DEMAND

- Residential, commercial, and industrial natural gas demand have registered long-term declines that may be moderated but are unlikely to be reversed.
- The major source for rapid growth in natural gas demand is the electric power sector. Power demand growth is extremely likely as new uses for electricity (possibly including electric vehicles) overcome the effects of energy efficiency and conservation.
- Much of any electricity demand growth will be met by gas-fired generation. Natural gas demand from the US power sector could grow from roughly 19 billion cubic feet (Bcf) per day today to as much as 35 Bcf per day by 2030.
- Natural gas–fired power plants have cost, timing, and emissions advantages compared to coal-fired plants. However, natural gas use for power generation over the long term depends on how strict greenhouse gas (GHG) emissions targets will be and how other competing or complementary technologies (nuclear, carbon capture and storage, and renewables) develop over time.
- The infrastructure needs and higher costs will likely limit significant growth in natural gas vehicles, which now number a few hundred thousand in the United States. Very significant policy support would be needed, which would compete with policy support for higher efficiency, biofuels, and electric vehicles. The most likely growth market for natural gas in transportation would be through the electric power sector.
- Liquefied natural gas (LNG) exports from either British Columbia or Alaska (already an LNG exporter) may be competitive into high priced oil-linked Asian markets, but significant exports from the US Lower 48 are problematic.

Natural gas is one of the United States' major energy sources. It keeps about a quarter of the country running; that is, it provides almost 25 percent of total US primary energy demand. This growth was built up over the second half of the twentieth century. Prior to that it was a local fuel. During World War II, as pressure mounted on US oil supplies, President Franklin D. Roosevelt wrote to his Secretary of the Interior, "I wish you would get some of your people to look into the possibility of using natural gas. I am told that there are a number of fields in the West and the Southwest where practically no oil has been discovered but where an enormous amount of natural gas is lying idle in the ground because it is too far to pipe to large communities."*

But it was only after World War II that these fields were connected to markets. In the decades that followed natural gas became a continental energy resource, with the development of the network of major pipelines that ties producing areas to demand centers.

*Daniel Yergin, *The Prize: The Epic Quest for Oil, Money, and Power* (New York: Free Press, 2009, new edition), p. 361.

The unconventional revolution shifts natural gas from a constrained energy resource to an abundant one. How might this shift change the US energy mix? Where are the markets for this growing supply? An examination of the traditional residential, commercial, and industrial sectors, presented below, suggests that these markets are mature for the most part, with little prospect for growth.

There are, however, other possibilities for substantial expansion in natural gas demand. After residential, commercial, and industrial, the fourth market is the electric power sector, which has for many years been viewed as the key long-term driver of natural gas demand. Another is in the transportation sector, where there may be an opportunity for natural gas to substitute, directly or indirectly, for petroleum-based vehicle fuels. (We discuss this in the next chapter). Another is in the global market for LNG, where the shale gas resource could make North America a competitor as an LNG supplier.

This chapter examines current markets for natural gas and the potential for LNG exports. The next chapter looks at possibilities for increasing natural gas use in transportation. Chapter VI specifically focuses on the dynamics of the electric power industry and the determinants of additional natural gas demand in that sector.

THE MATURE MARKETS FOR NATURAL GAS—RESIDENTIAL, COMMERCIAL, AND INDUSTRIAL

Three of the current main markets for natural gas show few prospects for growth. Natural gas demand from the residential and commercial sectors has remained flat over the past few decades as the effects of population and household growth have been offset by population shifts to warmer climates in the United States and the increasing efficiency of appliances. Energy efficiency has been emphasized in recent legislation and regulation in the United States, including the American Recovery and Reinvestment Act of 2009 and stricter federal and state standards for natural gas appliances and building codes.

In Canada the 1992 Energy Efficiency Act was amended last year to promote high-efficiency residential and commercial appliances and clean energy initiatives with the goal of reducing Canada's GHG emissions by 20 percent by 2020. Among the provincial mandates are Ontario's Green Energy and Green Economy Act of 2009, which similarly promotes higher appliance efficiency and the use of alternative fuels.

Furthermore, it has not been the case, nor does it seem likely in the future, that new appliances will be introduced into the residential and commercial sectors and consume substantial additional quantities of natural gas—in contrast to electricity, as we discuss in a later chapter. Indeed, natural gas is losing applications to electricity (such as ground source heat pumps), and this continues to contribute to the decline of residential natural gas demand.

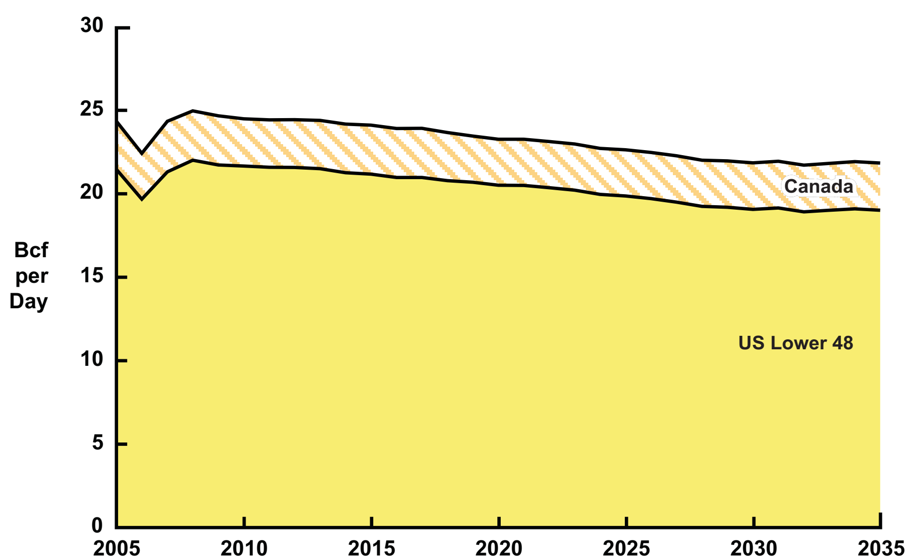
There are differences in the outlook for residential and commercial natural gas demand between Canada and the United States, owing primarily to differences in climate. There is not the same opportunity to reduce space-heating needs through migration to warmer climates in Canada. In contrast to the United States, Canadian natural gas demand from these two sectors is expected to increase slightly over the next 25 years. Because of the much larger size of the US market, the overall effect on North American natural gas demand from these sectors is a long-term decline (see Figure IV-1).

US Industrial Demand

Prospects for natural gas demand in the US industrial sector also do not point to growth. There has been a gradual but substantial drop in US industrial natural gas demand since the mid-1990s, prompted by the decline of heavy manufacturing in the US economy, rising natural gas prices, and dramatic efficiency gains; since 1996 there has been a 46 percent reduction in the quantity of natural gas consumed per unit of output created.* On top of this, the eight industries that account for 90 percent of industrial sector natural gas demand—food, nonmetallic minerals, primary metals, chemicals, refining, paper, fabricated metals, and transportation equipment—were all hit hard by the Great Recession of 2008–09. US industrial natural gas demand declined by 8 percent in 2009 alone, falling to a level that was 30 percent lower than in 1996 in absolute terms. A resumption of long-term economic growth and anticipated regulation of industrial GHG emissions will likely not be sufficient to overcome continued improvements in energy efficiency. As a result overall natural gas demand in these industries is expected to decline in the coming decade. Perhaps the prospects of growth in these industries will have to wait until sufficient confidence in sustainably low

Figure IV-1

Residential and Commercial Sector Demand



Source: IHS CERA.
00112-29

*See the World Economic Forum/IHS CERA report *Towards a More Energy Efficient World.*

natural gas prices has built up to a point at which industry players are prepared to proceed with significant investments in new gas-intensive facilities. But natural gas prices would be only one factor among many in any such decision.

However, there are several specific industrial growth possibilities. A small growth area for natural gas is in US ethanol production, where natural gas demand could increase from around 0.8 Bcf per day in 2009 to 1 Bcf per day in 2015 to meet the federal ethanol production mandate of 15 billion gallons by 2015, up from just under 11 billion gallons in 2009.* In addition, some elements of the petrochemical industry could benefit from lower prices of natural gas feedstocks made possible by the unconventional natural gas revolution. Whether there is much demand growth potential from this industry remains to be seen.

Canadian Industrial Demand

The one industrial sector where natural gas demand is definitely expected to grow is the Canadian oil sands. The oil sands represent the single largest portion of Canadian natural gas demand, accounting for one fifth of the total. Although oil sands development faces a number of environmental and economic challenges, this industry is expected to be the major source of increased industrial demand for natural gas over the next 25 years, accounting for more than 4 Bcf per day of natural gas consumption by 2035, according to IHS CERA estimates.** This level of demand takes account of the high priority that oil sands producers are placing on improving the efficiency with which they use natural gas.

Figure IV-2 shows the outlook for industrial natural gas demand in the US Lower 48 and Canada.

THE FOURTH MARKET FOR NATURAL GAS: POWER GENERATION DEMAND COULD DOUBLE

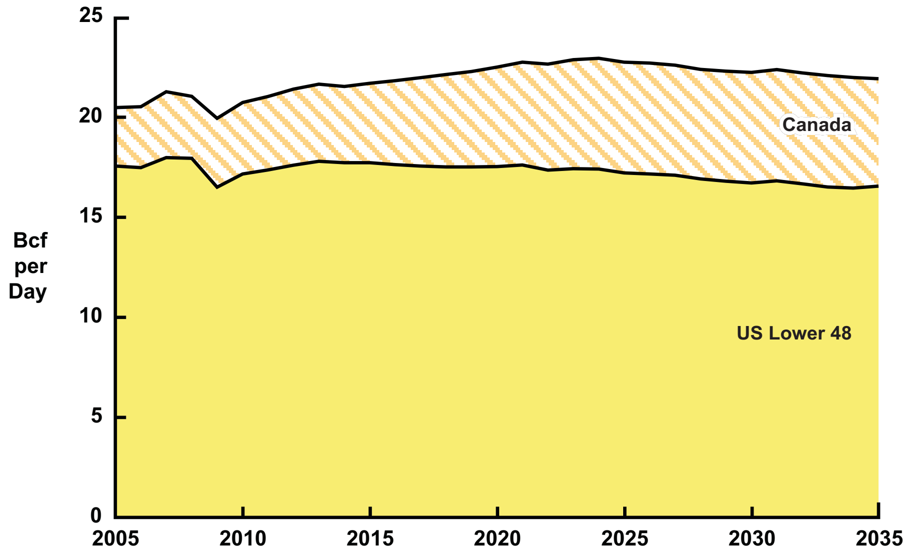
In contrast to the expected demand profiles in the residential, commercial, and industrial markets for natural gas, the electric power sector remains the key to future growth in natural gas demand. However, the degree to which natural gas penetrates the power market will depend in large measure on the stringency of GHG regulation and the response of nuclear and renewable generating options to incentives and/or mandates, GHG regulation, and carbon prices. These issues are discussed in more detail in Chapter VI, which looks at natural gas in the context of power sector dynamics.

However, looking at power sector natural gas demand overall, the outlook is for a near doubling of natural gas demand. In our reference case outlook we project North American electricity demand to grow at an annual rate of 1.4 percent, with the result that power sector demand for natural gas in North America grows from 20 Bcf per day in 2009 to more than 38 Bcf per day by 2035 (see Figure IV-3). Growth in natural gas use for power generation in Canada is expected to be particularly strong. This will be driven largely by Ontario's

*This estimate assumes an average consumption of 26,600 British thermal units (Btu) of natural gas per gallon of ethanol production in 2009 and a 1.5 percent annual efficiency gain.
**See the IHS CERA Special Report *Growth in the Canadian Oil Sands: Finding the New Balance.*

Figure IV-2

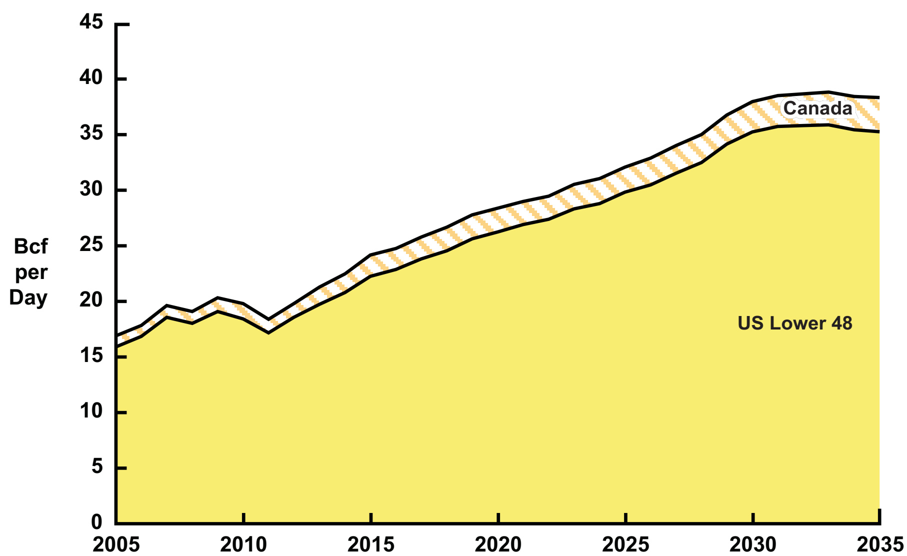
Industrial Sector Natural Gas Demand



Source: IHS CERA.
00112-30

Figure IV-3

Power Sector Natural Gas Demand



Source: IHS CERA.
00112-28

retirement of all of its coal generation in order to reduce GHG and other emissions. In the longer term, gas-fired generation capacity additions are required to meet growing power needs in Canada alongside capacity additions to both renewables and nuclear.

OVERSEAS MARKETS: WHAT ARE THE POSSIBILITIES TO GROW NORTH AMERICAN LNG EXPORTS?

There is another potential market for North American natural gas that has not been part of the national energy discussion until very recently (except possibly for stranded Arctic natural gas). The abundance of the natural gas resource base created by the unconventional revolution portends a possible new option. Could North America become a major source of gas for export as LNG? This would build on the small LNG volumes currently being exported from Kenai, Alaska—one of the first LNG export terminals in the world, dating back to 1969. It would also challenge traditional assumptions about North America's role in the global market for LNG. Indeed it would turn those assumptions on their head; for instead of being a major new market for LNG, as seemed inevitable just a couple of years ago, North America would become a new supplier.

Distance to the liquefaction and shipping terminal and the additional distance to markets are key elements. The possibility of LNG exports is being seriously considered as an outlet for natural gas from the new shale plays in British Columbia. Further, the upcoming open seasons for the Alaskan pipelines will likely include a Valdez LNG export option. Much of the Alaskan resource is low-cost associated gas produced from oil wells and therefore should be able to compete with British Columbia gas on cost grounds. The British Columbia option will include costs for the gas supply, most likely an expansion of the Westcoast system and a lateral pipeline to Kitimat (the proposed terminal location on the Pacific coast). The costs of liquefaction facilities will not be a major competitive differentiator between these two projects.

The key to success for such an endeavor lies not only in the large volumes associated with shale plays; it may also depend on the existence of a significant commodity price arbitrage—that is, the difference between natural gas and oil prices on an energy equivalent basis. In Asia, LNG is typically delivered under long-term contracts based on oil-linked prices. If the difference between North American natural gas prices and prices in oil-linked markets could be guaranteed to be sustained, then LNG exports from Alaska, British Columbia, and even from the US Gulf Coast could become economically viable.

But this should not lead to the conclusion that any of these projects will actually move forward. Many projects from other gas-producing countries around the world can be expected to compete for the available market, and the size of that market will limit the number of projects that can go forward. Nor can one conclude that projects will move forward in order from lowest to highest cost. Many factors determine which projects proceed, including commercial and political relationships, technology, concerns about security or diversity of supply, geography, and the negotiating positions of the parties.

Moreover, policy issues may affect the relative ability for North American LNG exports to proceed. For Canada, which has long been a natural gas exporter, access to export markets outside the United States might indeed be an attractive option. In fact, Canada might actively seek such diversification. However, for the United States concerns about energy security might trump economic considerations and prevent LNG export projects from progressing. On the other side, however, concerns about the value of the US dollar and the US balance of payments deficit might support the case for LNG exports, especially for gas that would be stranded owing to lack of pipeline connections to the major continental markets.

The unconventional natural gas revolution has made the unthinkable thinkable. It is now possible to imagine scenarios in which significant North American LNG exports might enter the global natural gas market. However, there would be many hurdles, including competition from other major suppliers, particularly in the Pacific Rim, and uncertainty about the long-term market prices in destination countries that are necessary to support the high capital costs of the LNG supply chain.

CHAPTER V: NATURAL GAS IN TRANSPORTATION

CHAPTER V: NATURAL GAS IN TRANSPORTATION

- There may be an opportunity to replace oil with indigenous natural gas supply—particularly in the transportation sector.
- Even with policy support, this is likely to be constrained by the infrastructure needs and the higher costs of natural gas vehicles along with the economic "competition" from greater fuel efficiency, biofuels, and electric vehicles (EVs).
- The best growth opportunity in transportation is for urban fleets.
- The most likely growth market for natural gas in transportation would be through the electric power sector.

Today there is very little natural gas used for transportation, but the potential for increasing natural gas use in this sector is getting particular attention. It could address a series of major issues, in particular the energy security objective of reducing oil usage, thereby reducing oil imports, which has been a tenet of US national policy for many years.* In addition, the lower carbon footprint of natural gas compared to gasoline and diesel could address more recent policy priorities of reducing carbon dioxide emissions to meet climate change objectives. But this analysis concludes that achieving that potential faces many obstacles.

THREE NEW COMPETITORS TO NATURAL GAS VEHICLES: EFFICIENCY, BIOFUELS, AND BATTERIES

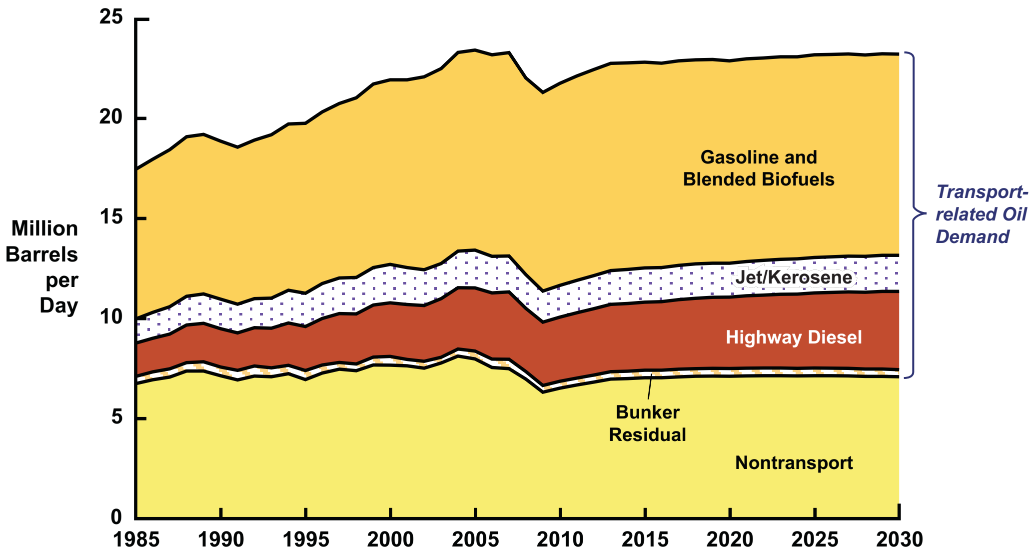
The primary use of oil in North America is in the transportation sector, ranging from gasoline for the light-duty vehicle fleet through diesel in the freight industry, jet fuel in aviation, and residual bunker fuel for marine transport. The other major demands for liquid hydrocarbons are as industrial feed stocks and in space-heating applications. Figure V-1 shows the outlook for North American oil demand in a business-as-usual scenario (including the impact of the tightening of the Corporate Average Fuel Economy [CAFE] standards for light-duty vehicles).

Three major initiatives are already in place to reduce oil use in the transportation sector. The first is the drive for increased fuel efficiency. The first federal mileage standards were put in place in 1975, requiring a doubling of new passenger car fuel efficiency by 1985 to 27.5 miles per gallon (mpg). They have remained at that level until today. New standards were passed into law in December 2007 and were accelerated in 2009. They will raise new passenger car efficiency to 38 mpg by 2016. The efficiency of light trucks (a category that includes pickup trucks and sport utility vehicles) will increase from 23.1 mpg today to 28 mpg by 2016. The reference case outlook shown in Figure V-1 assumes that passenger car fuel economy increases to 45 mpg by 2030. Increased fuel efficiency will obviously reduce gasoline demand in the United States.

*Currently oil imports, on a net basis, constitute about 53 percent of total oil demand—a reduction from its high point owing to the recession and increased efficiency of the motor fleet.

Figure V-1

US and Canadian Oil Demand for Transportation Fuels: Reference Case



Sources: IHS CERA, US Department of Energy, and US Department of Transportation.
00112-34

The second initiative is the mandated introduction of biofuels, principally ethanol, into the motor fuel mix. Current legislation requires 36 billion gallons of biofuels to be produced by 2022, providing about 20 percent of the fuel mix. This will not only reduce oil usage in transportation, it will also slightly increase natural gas demand because natural gas is used to make corn-based ethanol. However, only 15 billion gallons of the total requirement of 36 billion gallons is allowed to come from corn-based ethanol plants. The remainder must come from cellulosic or other advanced technologies that are not fueled by natural gas.

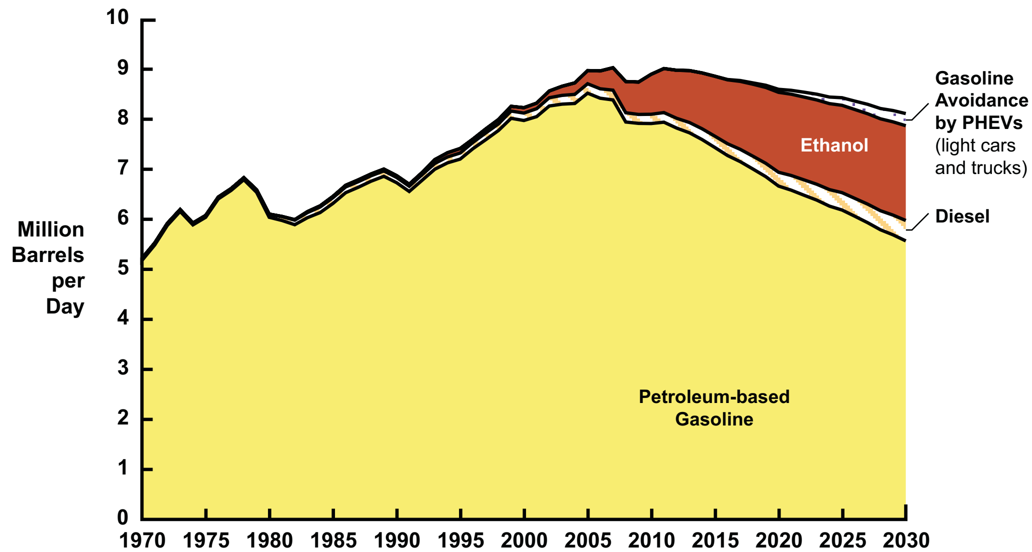
The third initiative that may reduce oil demand is the concerted multibillion-dollar effort by the federal government, automakers, entrepreneurs, and innovators to develop an efficient battery that will make EVs competitive at scale. Some $2 billion of stimulus funds were authorized under The American Recovery and Reinvestment Act of 2009 for manufacturers of advanced batteries and other components for EVs. If successful, the results of this and similar initiatives would contribute to a wholesale transformation in the transportation sector.

Thus the introduction of natural gas vehicles (NGVs) at scale into the transportation sector has to be measured not only against oil reduction, but also in the framework of the competitive alternatives for reducing oil usage. Figure V-2 shows how the fuel mix for light-duty vehicles could evolve over the next 20 years, assuming aggressive efforts to improve vehicle efficiency, introduce biofuels, and make EVs competitive.

A major expansion in NGVs has to be considered in the context of the "peak oil demand" phenomenon that the entire developed world is experiencing. World oil demand, including that of the Organization for Economic Cooperation and Development (OECD), will grow

Figure V-2

US Light-duty Vehicle Fuel Demand in Aggressive Demand Reduction Scenario



Sources: IHS CERA and US Department of Transportation.
00112-33

again once the world shifts from recession to recovery. However, it is unlikely that all of the demand lost in the OECD will return, even over the long term. In fact, in retrospect 2005 will likely be seen as the peak year of oil demand in the OECD.* In the United States, gasoline demand almost certainly reached its peak in 2007 and may now—allowing for a temporary rebound coming out of the recession—be in a permanent decline.

How much difference could NGVs make to the market for natural gas? NGVs have successfully penetrated the vehicle markets in many other countries, growing from a total fleet of 1.3 million vehicles worldwide in 2000 to 9.6 million vehicles in 2008—approximately 1.2

Natural Gas Vehicles and Their Fuels

NGVs are powered by internal combustion engines but are fueled by natural gas rather than gasoline. There are two ways for natural gas to be used directly as a fuel. It can be stored in a tank at pressures up to 4,500 pounds per square inch. This is usually referred to as compressed natural gas (CNG). Existing vehicles can be retrofitted with a fuel tank that occupies part of the trunk space. For new vehicles, automakers may design and manufacture NGVs that do not have this restriction.

In the case of heavy duty trucks another option is for natural gas to be stored at very low temperatures as liquefied natural gas (LNG) in thermally insulated, high pressure tanks.

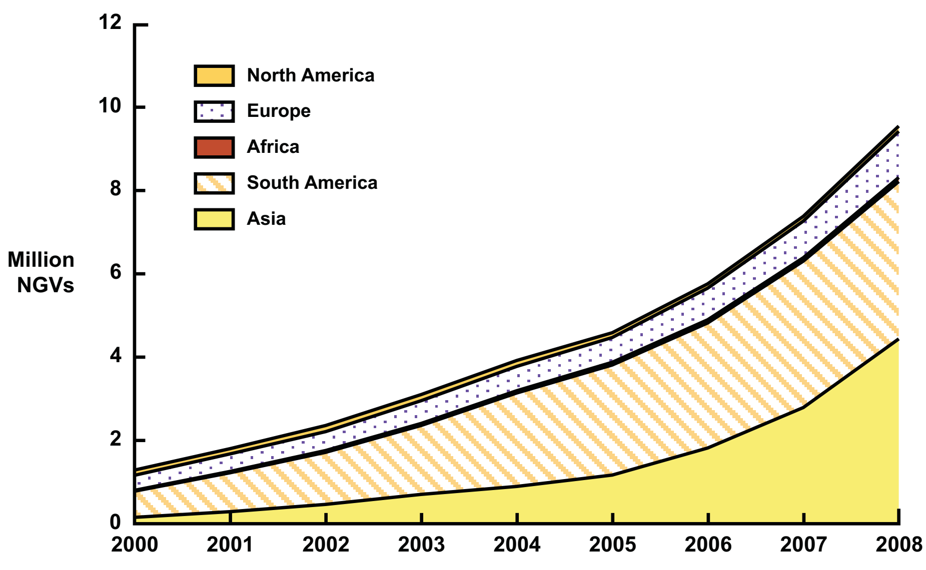
*See the IHS CERA Private Report *Peak Oil Demand in the Developed World: It's Here.*

percent of 828 million total light vehicles. These vehicles are primarily taxicabs and other passenger vehicles in Asia, South America, and more recently from a rapidly growing share of new registrations in Italy, owing to the tax-advantaged position of natural gas as a motor fuel and significant government incentives (see Figure V-3). In the United States, NGVs number under 200,000.

Could NGVs grow from a small niche into a scale alternative in US transportation? At one extreme, "scale" would mean converting all of the existing 237 million US light-duty vehicles to CNG. If the fleet could be converted instantaneously to CNG at 2010 CAFE standards, IHS CERA estimates that US natural gas demand would increase by 36 billion cubic feet (Bcf) per day—a 58 percent increase from current levels of US natural gas consumption (see Figure V-4).* This would replace some 7 million barrels per day (mbd) of gasoline consumption (or 5 mbd in the aggressive policy case illustrated earlier). Of course this cannot be done immediately. Even theoretically, it would take several decades to accomplish and would require long-term confidence in the adequacy of future natural gas supplies. The growing awareness of the scale of the shale gas resource base would support this potential. Canada has about 19 million passenger vehicles and light-duty trucks and would have similar incentive to convert to CNG despite being an exporter because substitution of this nature frees up additional export volumes of crude oil.

Figure V-3

Global Growth in Natural Gas Vehicles

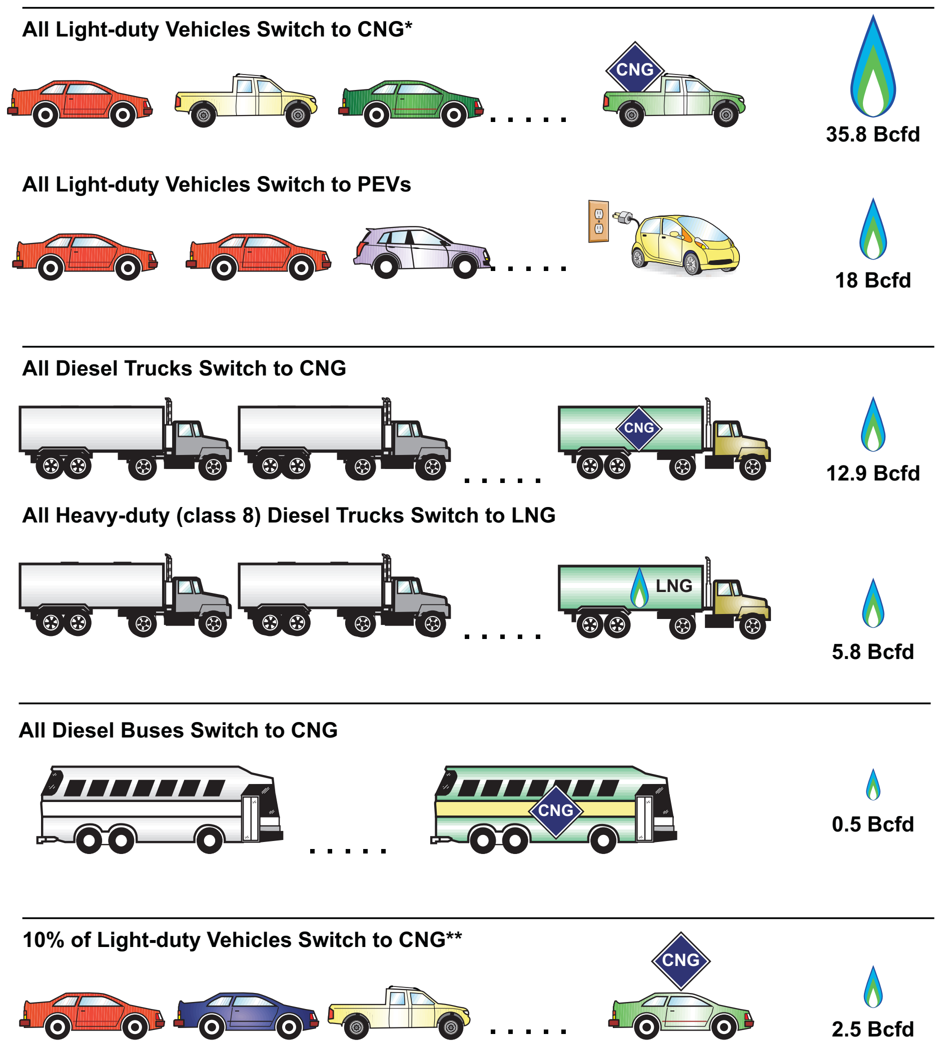


Source: International Association for Natural Gas Vehicles.
00112-10

*If the fleet average fuel efficiency were 38 mpg in 2020, in line with the aggressive policy case, the resulting theoretical natural gas demand from converting to CNG would be less than 25 Bcf per day.

Figure V-4

Potential for Natural Gas Demand from Transportation



Source: IHS CERA.
*Assumes 2010 CAFE standards.
**Assumes 2020 CAFE standards.
Note: Bcfd = Bcf per day; PEVs = plug-in electric vehicles.
00112-1

Other such hypothetical configurations can be imagined:

- A 13 Bcf per day increase from replacing the 2.3 mbd of diesel consumed by medium and heavy duty trucks with CNG. A subset of this group is the Class 8 heavy duty trucks which could consume 6 Bcf per day as LNG, replacing the 1 mbd of diesel now consumed by these trucks. That would be the equivalent of 10 percent of US oil imports.

- A 0.5 Bcf per day increase from replacing less than 100,000 barrels per day of diesel fuel consumption by the entire diesel bus fleet (as defined by the US Federal Highway Administration) with CNG.

However, there are challenges to be overcome if natural gas is to penetrate the transportation fuels market to a significant degree. To achieve even a 10 percent conversion of the passenger vehicles and light truck fleet by 2020 would require a ramp-up in the production of NGVs from essentially zero today to 25 percent of new sales by 2020. The impact on fuel demand would still be minor. If this penetration rate were achieved, US gasoline demand would fall by less than 0.5 mbd—equivalent to 5.5 percent of US gasoline consumption and 2.7 percent of total US oil demand. At the same time natural gas demand would increase by 2.5 Bcf per day.* Even this, however, would require a very large industrial and infrastructural transformation. And the costs would be significant.

Interest in NGVs is not new. It arose after the oil embargoes of the 1970s and again in the mid-1990s. On both occasions the interest faded, for three reasons:

- The lack of refueling infrastructure discouraged retail consumers from risking the purchase of a vehicle that they might not be able to refuel conveniently.
- The driving range of NGVs is less than gasoline vehicles because the energy density, measured in million British thermal units per gasoline gallon-equivalent, of CNG is 70 percent lower than that of gasoline or diesel (see Figure V-5).
- NGVs cost more than comparable gasoline vehicles, especially if they are dual-fueled—having two fueling systems and two fuel tanks (CNG and gasoline) to allow a vehicle to reach an appropriate CNG refueling site if necessary.

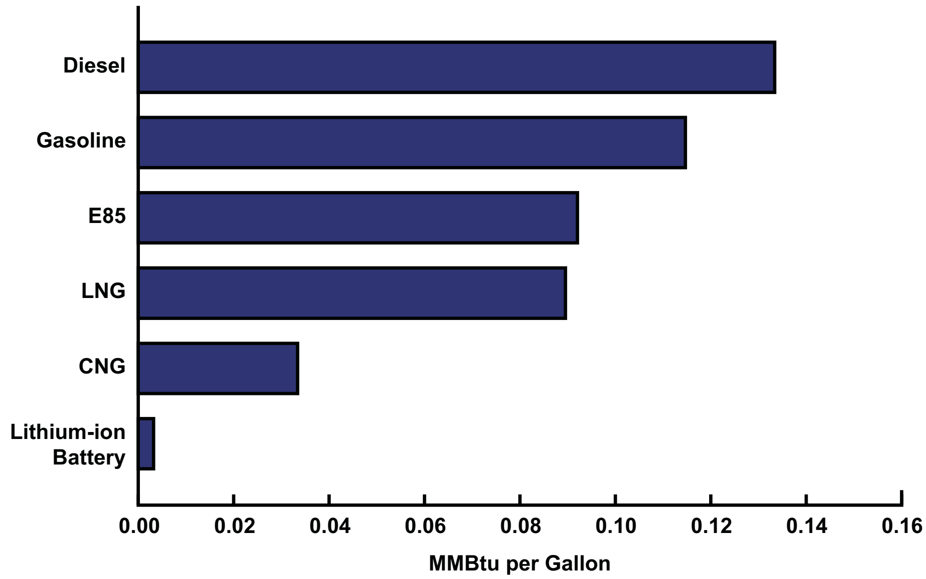
LIGHT-DUTY VEHICLES

The incremental cost of NGVs poses a significant hurdle. For example, in the United States the advertised price difference between a light-duty Honda NGV and a similar gasoline-powered vehicle in 2008 was $6,830, as too few NGVs were produced to achieve economies of scale.** But even if any combination of higher production volumes to realize economies of scale, technology improvements, or government incentives reduced the price differential to $2,000, the total incremental cost to consumers of purchasing enough NGVs to achieve a 10 percent penetration rate by 2020 would be $50 billion before any government credits or grants. Lower fuel costs would help offset some of the higher up-front purchase costs. But it would take almost six years to recover the higher purchase price from fuel savings—longer than the 24 to 36 months that most consumers appear willing to accept.***

*Based on continuing improvements through the remainder of the decade beyond the 2016 CAFE standards.
**Source: http://automobiles.honda.com/civic-gx/faq.aspx.
***The 24 to 36 month "acceptable" payback period is based on empirical studies of implied discount rates associated with consumer decisions regarding energy efficiency investments which show that such discount rates are typically in the 20 to 30 percent range. See Ronald J. Sutherland, "'No Cost' Efforts to Reduce Carbon Emissions in the US: An Economic Perspective," *The Energy Journal,* Vol. 21, No. 3, 2000.

Figure V-5

Energy Density of Transportation Fuels



Source: IHS CERA.
00112-8

Even if consumers accept a six-year payback from fuel savings, they will need to be certain that sufficient refueling options are available. Before any significant adoption of CNG vehicles can take place, a minimum critical mass of CNG refueling infrastructure will be required. At present there are 162,000 gasoline stations in the United States but only some 1,100 stations that sell CNG. At a cost of $500,000 to $750,000 for a two hose CNG station, ensuring that CNG was available at one in ten locations would require an investment of $8 billion to $12 billion. Federal income tax credits are available for CNG refueling station investment costs, but these cover only $30,000 of the estimated $500,000 cost of a refueling station. This would reduce the investment requirement by service station owners by less than 10 percent.

Another option for NGV owners is to have a home refueling system, although these can take several hours to refill a nearly empty CNG tank.* The installed cost of a home fill system is cited at between $4,500 and $5,500 after the $1,000 federal income tax credit. Even at the July 2008 peak gasoline–residential gas price spread of $1.55 per gallon equivalent, the payback period for the incremental cost of buying both an NGV and a home refueling system is more than ten years. Even ownership of more than one NGV in a family would not reduce the payback to levels that consumers have shown themselves prepared to accept.

*CNG stations use a quick fill system that provides a refueling time similar to that of a gasoline pump. Such systems are not available for home use.

Combining these infrastructure costs with incremental vehicle costs raises the total to about $60 billion over ten years to reduce crude oil imports by 0.5 mbd. However, if NGVs continued to account for 25 percent of new vehicle registrations for another decade the volume of natural gas demand that would ultimately be generated would be nearer 7 Bcf per day—displacing some 1.5 mbd of gasoline demand.

Significant subsidies would likely be required to increase consumer demand for NGVs and to build the necessary refueling infrastructure to support these vehicles. At present federal income tax credits are available for NGV passenger vehicles and trucks. These credits are set to expire on December 31, 2010. A failure to renew these credits at the end of the year will have a significant negative impact on new NGV sales.

Some subset of vehicle owners will shift to natural gas. To gain widespread acceptance, however, new technologies generally need to offer clear advantages over incumbent technologies. Do NGVs offer greater utility and value for the same price? Particularly because of their operating range limitations, it is not clear that they do. The range of a vehicle is a function of energy density (million British thermal units [MMBtu] per unit of volume) and engine efficiency (miles per MMBtu). The lower energy density of CNG forces compromises that might limit NGVs' appeal to consumers and businesses. Do NGVs offer equal utility for a significantly lower price? For NGVs to compete on price they would require continued incentives. Alternatively purchases could be mandated, forcing the costs of NGVs to be borne across the wider fleet in order to be price competitive with gasoline vehicles.

As emphasized above, NGVs cannot be evaluated against an unchanging automotive landscape. For example, more efficient engines make it even more challenging for NGVs to compete. As gasoline-powered vehicles become more efficient, the fuel cost savings of NGVs will decrease because the number of gallons of fuel against which the price spread can be applied will also decrease.

HEAVY-DUTY VEHICLES

The incremental cost of converting a heavy-duty truck to CNG or LNG is $40,000 to $70,000, with federal income tax credits of up to $32,000 per truck available. Converting 10 percent of today's heavy duty trucks would cost $31 to $54 billion before federal income tax credits. There are three ways to use natural gas in heavy-duty trucks:

- CNG with spark ignition
- LNG with spark ignition
- LNG (90 percent)/diesel (10 percent) with compression ignition

Spark ignition engines have an engine efficiency of only 35 percent, whereas compression ignition engines have an engine efficiency of 45 percent. Further, CNG suffers from having only 40 percent of the fuel density of LNG—therefore requiring more refueling stops on any long journey or reducing the payload that can be carried. Any combination of these effects will increase travel times, which challenges the competitiveness of CNG versus LNG vehicles.

But operators of heavy-duty vehicles using LNG face a similar hurdle in terms of fuel density. LNG has 67 percent of the fuel density of diesel, Allowing for this operational drawback and the extra purchase price of the vehicle (net of tax credits), an LNG compression ignition truck needs the LNG price to be $0.80 per diesel gallon equivalent below the actual diesel price to compete with a diesel truck. At present that spread is only approximately $0.50 per diesel gallon equivalent.

The LNG/diesel compression ignition option appears to be favored, especially for long-haul Class 8 diesel trucks. But infrastructure along the main highways and the right fiscal incentives will need to be in place for significant market share to be built.

FLEET VEHICLES HAVE THE POTENTIAL

The economics are much better for centralized fleet operations—taxis, municipal buses, light-duty delivery trucks, and work fleets of utilities (gas, power, water, and telecoms), among others. One of the main benefits to using natural gas in centralized fleets is the centralized refueling infrastructure. Unlike for long-haul vehicles, where CNG or LNG is needed throughout the country, centralized fleets need only regional or local refueling terminals. These centralized fleets thus limit the amount of CNG refueling infrastructure that is needed and guarantee a threshold throughput that would enhance the infrastructure economics of NGVs.

Centralized fleets are also promoted as a way to improve local urban air pollution compared to gasoline and diesel, as natural gas emits fewer particulates into the atmosphere. An example of this is the 2009 Clean Truck Incentive Program at the Port of Los Angeles, which has a goal of putting 1,000 clean trucks into the port's fleet that run on any of CNG, LNG, or electricity.

As we noted earlier, the volumes of natural gas that could be consumed in fleet vehicles are not large. All the buses in the United States between them would consume some 0.5 Bcf per day. But there are initiatives among an alliance of fleet operators of light-work trucks to aggregate sufficient vehicle orders that would allow them to negotiate with a single automotive manufacturer to benefit from economies of scale. In these circumstances, the volumes of natural gas demand would begin to build more rapidly, as these vehicles tend to have below-average fuel economy and be driven more miles than average.

Thus, it is understandable that most of the attention on increasing natural gas demand in the transportation sector focuses on fleet vehicles and long-haul trucks, as these appear to provide the lowest-cost entry to growing displacement of petroleum products.

ELECTRIC VEHICLES

There is yet another way for natural gas to become a more significant part of the transportation sector. That is indirectly—using natural gas to generate electric power for EVs. IHS CERA estimates that replacing all light-duty vehicles in the United States with EVs and using natural gas–fired electricity to charge their batteries would increase US natural gas consumption by 18 Bcf per day—nearly a 30 percent increase from current natural gas consumption of

62 Bcf per day. This is half the estimated increase of 36 Bcf per day noted earlier if all light-duty vehicles were converted to NGVs overnight because natural gas demand per mile driven by EVs is lower than for NGVs (see Figure V-4). An electric motor is significantly more efficient than current internal combustion engines, even when the upstream energy losses in the refining and electric generation processes are considered. Increasing efficiency of internal combustion engines required by future CAFE standards will reduce this differential but will likely not eliminate it.

The incremental up-front price of EVs (whether plug-in hybrid electric vehicles or battery electric vehicles) today is estimated to be $10,000 to $18,000 compared to a conventional gasoline vehicle. If this price differential could be reduced to $5,000 through economies of scale, a (so far elusive) breakthrough in battery technology, increased tax credits, or some combination of these effects, the cost of converting 10 percent of the vehicle fleet would be some $120 billion over the next ten years. Annual savings in fuel cost for an all-electric vehicle would be approximately $800.* This implies a more than six-year payback from fuel savings, in line with NGV options. Current EVs suffer from insufficient battery working life. The payback calculation assumes that the vehicle owner does not face the cost of a new battery pack within the six-year period. But, as was the case for NGVs, more efficient gasoline engines will increase the payback period.

EVs have certain advantages over NGVs. First the need for new recharging facilities is likely to be lower; many vehicle owners would recharge at home. Using a standard 110 volt outlet can require several hours to charge a battery with enough energy for the working range of the vehicle. However, an upgrade to 220 volt service would significantly reduce charging time. New facilities would have to be built for urban vehicle owners who only have access to on-street parking and for vehicle owners who travel beyond the vehicle range from home.

Plug-in hybrid electric vehicles can also run on gasoline if there is no recharging facility immediately available, which increases their range and reduces the need for an immediate breakthrough in battery technology. For example, an electric range of only 40 miles between recharges would account for some two thirds of all vehicle miles driven in light-duty vehicles in the United States.

The addition of electricity into the transportation sector appears to be competitive with natural gas directly as a fuel. The aggregate investment in new infrastructure for electric vehicles is lower than for NGVs and can be grown along with demand rather than requiring a critical mass of investment before growth can begin. On the other hand, the additional purchase cost of EVs favors NGVs. IHS CERA's analysis therefore suggests that natural gas may very well become an important component of the transportation sector, whether directly in NGVs or via the generation of electric power to recharge the batteries of an EV.

*This is based on 12,500 miles driven at 28 miles per gallon for gasoline versus 3.5 miles per kilowatt-hour (kWh), a gasoline price of $2.70 per gallon, and an electricity price of $0.1106 per kWh.

CHAPTER VI: THE FUEL MIX IN ELECTRICITY GENERATION: HOW WILL IT CHANGE?

A SHORT GUIDE TO NATURAL GAS USAGE IN ELECTRIC POWER GENERATION

Natural gas plays an important role in the North American power sector; the power sector, in turn, accounts for more than a quarter of North American natural gas consumption. In 2008 US power generation consumed 18.2 billion cubic feet (Bcf) per day and Canada 1.1 Bcf per day of natural gas. The preliminary estimate for US power generation demand for natural gas in 2009 is 18.9 Bcf per day, with Canada remaining at 1.1 Bcf per day.

In the United States natural gas–fired power plants account for 39 percent of installed capacity, but because of the role that natural gas plays in the power sector, it is responsible for only about 21 percent of the actual generation of electricity (see Figure P-1). In Canada natural gas has a smaller role, accounting for 8 percent of installed capacity and 17 percent of total generation.

Natural gas–fired power plants in place today provide a flexible power source to follow changes in power demand, to maintain power system reliability, and to back up the growing amount of intermittent generation from renewable power resources, especially wind. The role of natural gas in the North American power sector continues to expand because natural gas–fired technologies make up close to one third of planned power generation capacity additions.

Three main power generation technologies are fueled with natural gas:

- **Combustion turbines** (similar to aircraft jet engines) provide rapid start-up and quickly reach their peak output.
- **Steam boilers** use natural gas to heat water, making high pressure steam to drive steam turbines. These units can be used flexibly in a peaking and cycling capacity.
- **Combined-cycle gas turbines (CCGTs)** burn gas in combustion turbines and then use their hot exhaust gases to heat water to run a steam turbine. These plants run at very high efficiencies and are most economically deployed in base-load or high-load factor applications. They can also provide peaking and cycling capacity.

The natural gas share in the generation mix varies in the short run depending on the price of natural gas relative to competing generation fuels. In the longer term the investment decisions regarding fuels and technologies move the capacity mix and, in turn, the fuel mix.

The unconventional natural gas revolution is reinforcing the two-decades-long trend—shown in Figure P-2—toward an increased share for natural gas in the US power generation fuel mix.

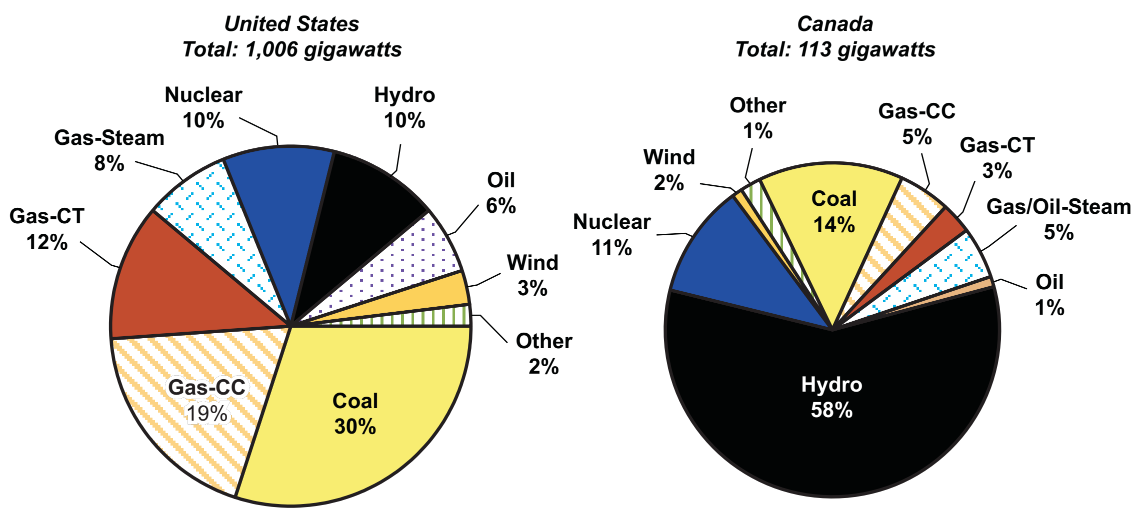
Natural gas–based power generation is among the two thirds of power production that uses fossil fuels. The environmental implication is shown in Figure P-3—the carbon footprint of the North American power sector, where coal-fired generation accounts for about 80 percent of power sector carbon dioxide (CO_2) emissions and natural gas–fired generation accounts for roughly 20 percent.

Clearly any climate change policies designed to stabilize or reduce CO_2 emissions will have a major impact on the power sector. Consequently any assessment of the impact of the unconventional natural gas revolution on the North American power sector must involve the context of policy choices under consideration today to address the climate change challenge of the future.

In this chapter, we focus more on the US power sector because of its greater overall scale, because the gas consumption is so much greater, and because it is more carbon intensive than the Canadian power sector. However, many of the insights are as applicable to the issues Canada faces in achieving its own low carbon future.

Figure P-1

US and Canadian Generation Capacity Technology Mix, 2008



Source: IHS CERA.
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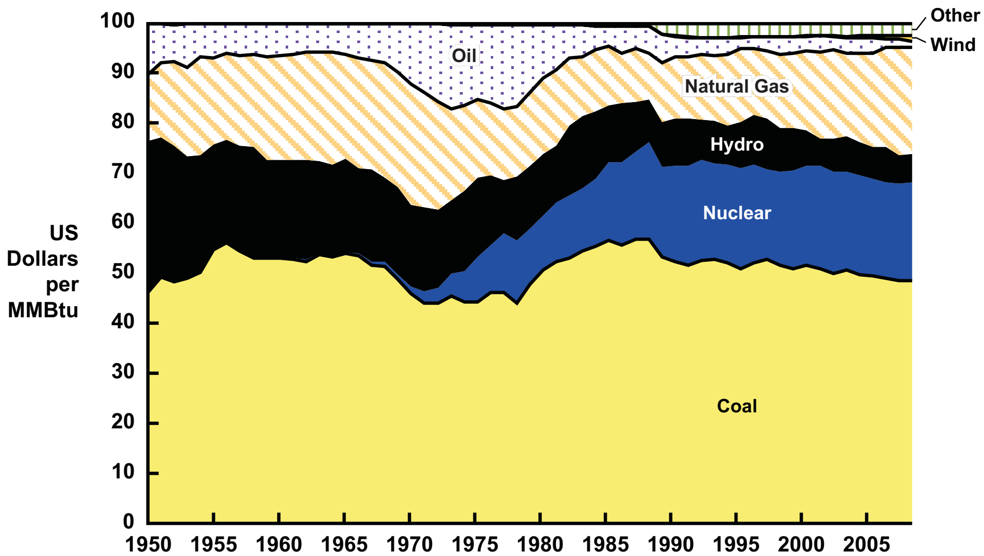
Figure P-2

Share of US Power Generation, 1950–2008



Source: IHS CERA.
Data Source: US Energy Information Administration.
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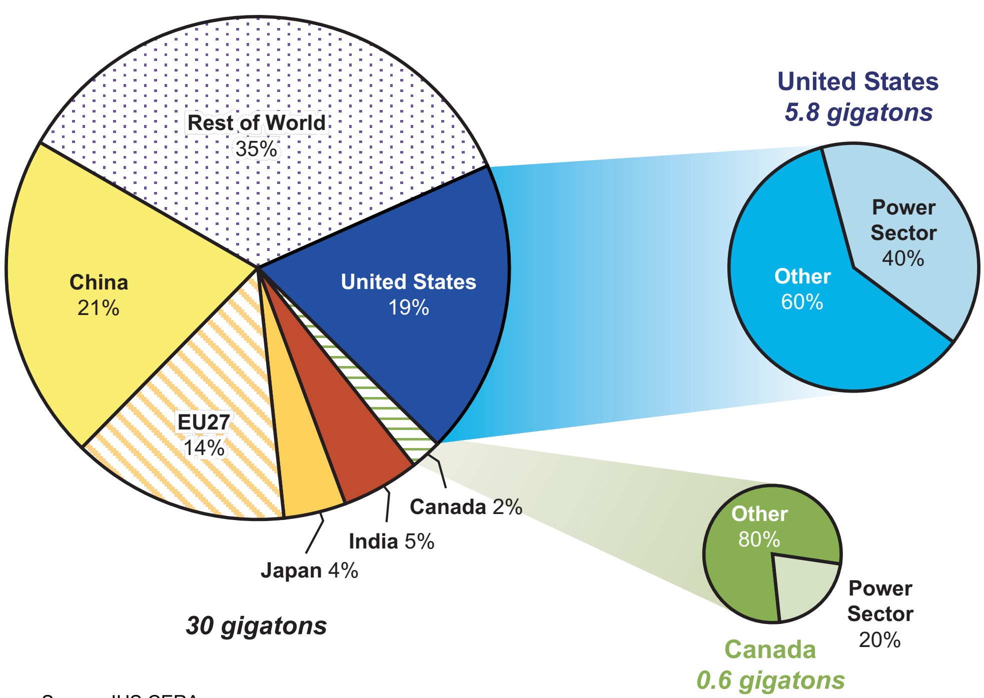
Figure P-3

Global, US, and Canadian CO_2 Emissions, 2008



Source: IHS CERA.
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CHAPTER VI: THE FUEL MIX IN ELECTRICITY GENERATION: HOW WILL IT CHANGE?

- The abundance of new natural gas will increase the share of natural gas–fired generation in the North American power sector.
- It will expand the role of natural gas–fired generation technologies to back up renewable power resources—a new role for natural gas.
- Natural gas–fired generation consumed 3 Bcf per day more natural gas in 2009 than in 2008 when adjusted for the impact of the Great Recession. Displacement of coal-fired generation contributed significantly to this number. But there is a limited pool of "spare" gas-fired capacity that prevents wholesale displacement of coal with natural gas.
- In addition to this fuel switching, the power sector can reduce near-term CO_2 emissions by replacing existing coal-fired plants with new gas-fired plants and converting existing coal-fired plants to burning gas. This would require substantial investment and would result in growth of natural gas use. But power companies would be concerned about longer-term requirements to further reduce CO_2, which would also affect gas-fired facilities.
- The power industry has a multiple-decade planning horizon. If the goals include cutting carbon emissions substantially over the long term, such as the often-cited 80 percent reduction by midcentury, aggressive development and deployment of zero-carbon technologies, including nuclear and CCS, will need to take place today.
- But a gas-based solution, on its own, does not provide a long-term path to a low-carbon future. To get there will require a portfolio of options including not only natural gas but also some mix of nuclear power, renewables, and breakthroughs in CCS.

The major growth market for natural gas is the electric power sector. This chapter explores how the structure and operations of the electric power industry affect the opportunities to expand the use of natural gas and also the nature of the limits, which are not necessarily so obvious.

One question dominates the electric power industry in North America: *What to build?* This question would loom large under any circumstances. Unlike such sectors as transportation, where gasoline demand has peaked, electric power demand continues to grow as the economy grows. Over the next two decades US power consumption could grow by 30 percent, requiring 270 gigawatts (GW) of new capacity to meet both demand growth and plant retirements. In addition some share of existing capacity is retired each year and replaced by new capacity.

But the question has become even more urgent—and more complex and confusing—because of uncertainty over climate change regulation. Will there be a price or a cap on greenhouse gas (GHG) emissions? Will utilities be compelled to build more low-carbon or no-carbon generating capacity? How does the United States, which today gets 83 percent of its energy from fossil fuels, succeed in reducing its CO_2 emissions by the often-cited target of 80 percent by 2050—that is, within four decades?

These questions create a quandary for investment decisions in the power industry. Its traditional mandate is to provide reliable supplies of electricity at affordable costs. How does it accomplish that while also meeting carbon and other environmental objectives? The particular characteristics of the power industry—its long time horizons and its capital intensity—make this difficult. For when a power company makes a multibillion-dollar investment decision today, it is often making a 50- or 60-year decision because the capacity will be expected to last that long.

The emergence of unconventional natural gas is highly relevant to these questions along three dimensions:

- Natural gas is an abundant resource.
- The carbon intensity of natural gas is about half that of coal, the current mainstay of electric power generation in the United States.
- Natural gas is already playing an important new role—providing a flexible power source that is increasingly important for balancing the growing amount of intermittent renewable energy, primarily wind.

THE PERSPECTIVE OF THE POWER INDUSTRY

However, for the power industry, the answer is not so clear. Its response is constrained by experience, strategic uncertainty, and risk.

First, the experience of previous cycles in natural gas prices affects the outlook of the power industry. In the late 1970s national policy sought to banish natural gas from power generation on the grounds that it was in short supply and that, as the "prince of hydrocarbons," it was too valuable to burn in power plants. Coal was deemed a better choice. During the 1990s, when natural gas prices were stable and averaged about $2 per million British thermal units (MMBtu) (owing to a production capacity surplus that lasted until almost the end of the decade), there was a wholesale embrace of natural gas as the "fuel of choice." In the first years of this century, however, while the drill bit did step up activity in response to rising prices and demand, it did not bring forth the expected resources. Skyrocketing natural gas prices—at times higher than $10 per MMBtu, plus the accompanying high power prices—created a sense of energy crisis in parts of the country and, specifically, trauma in the power industry, including bankruptcies of some companies that were heavily dependent on natural gas. In the light of such experience, power companies remain cautious about expanding the use of natural gas further. They regard an assumption of long-term low and stable natural gas prices as too risky to be a basis for long-term investment decisions.

The second reason for caution is strategic uncertainty about climate change legislation and other environmental regulations. Natural gas can provide an important part of the path to stabilizing, and even reducing, power sector CO_2 emissions in the years to come by slowing the increases in CO_2 emissions from new capacity additions, backing up renewable power resources, and displacing some existing coal-fired generation.

If, however, policy requires very heavy reductions, and at the boundary an almost-complete elimination of GHG emissions, then even a lower carbon-intensive fuel such as natural gas faces the reality that it still emits CO_2. The future of all fossil fuel generating assets at that point becomes problematic. There are further uncertainties about technology, including those for CCS needed to extend the opportunity for fossil fuel–generated electricity. In such circumstances, nuclear power will likely become an important—and more competitive—option.

The third reason is risk management. There are so many unknowns about what will happen over the next 30 to 40 years—ranging from technology to costs to regulation to public opinion—that the prudent response is to avoid an overcommitment to any one fuel choice. For the industry the most prudent way to protect itself against future uncertainty is through a resilient, diversified portfolio. For many utilities this is fundamental to their strategies. They are loath to rely on an "all eggs in one basket" approach. The variability of expectations for natural gas prices over the past decade and a half contributes to that conviction.

WHAT DOES UNCONVENTIONAL NATURAL GAS MEAN FOR THE POWER SECTOR?

With all this said, what is the potential impact of the unconventional natural gas revolution on the power sector? To begin, a great expansion in natural gas supply would lower expected natural gas prices and increase the security-of-supply outlook. These changes favor an increase in the share of natural gas–fired generation technologies in the existing and planned generation fleet.

As we proceed in this discussion, it is important to keep in mind the physical constraints of the power system. While on simple arithmetic it may look straightforward to substitute natural gas for coal in base-load generation, the actual operating configuration of the power system creates significant constraints even with relatively low-priced natural gas. Understanding both the flexibility and the constraints is one of the topics of this chapter.

A second point to keep in mind is the difference in the investment time horizon between the North American natural gas industry and the electric power industry. An unconventional natural gas well may pay back in three years or less. A power station requires one or two decades. In terms of current investment, a significant market shift five or ten years down the line is far more consequential for a power company than for a natural gas producer.

ELECTRIC POWER DEMAND GROWTH

Expected growth in power consumption sets the pace for power infrastructure investment decisions. IHS CERA's outlook for electric power demand is that annual North American power growth will slow somewhat from the pace of the past decade to 1.4 percent annually in the decades ahead. This slower growth rate in power use reflects the impacts of higher electricity prices and greater energy efficiency. After the bounce-back from the Great Recession, this 1.4 percent annual increase means that the US power sector will still grow one-third larger within two decades—an additional 270 GW.

IHS CERA's power demand outlook also expects that the higher levels of power use will involve higher variations in power demand, ranging from minimum levels (for instance, in the middle of a spring night) to peak demands (during midday in a summer heat wave). The variations can be very large—the peak could be three times as high as the minimum.

Peak demands have been growing faster than average demands, a trend that is expected to continue. One reason is that residential and commercial power use, which moreover tends to be more weather-sensitive and therefore more variable, is increasing faster than industrial electricity use because of consumer adoption of new technologies. Over the past several decades the number and variety of electric end uses—such as personal computers, flat screen televisions, and cell phones—increased steadily in homes and businesses. The share of power consumption associated with these new appliances and equipment increased dramatically over time, offsetting increased efficiency of the traditional power end uses.

Perhaps the largest element of future power demand growth could arise if ground transportation is electrified—particularly cars, trucks, and rail transport of heavy goods. Yet, at the same time, new technologies that build a "smart grid" could enable the power demand swings to be partially moderated in the future.

WHAT TO BUILD?

US and Canadian power systems need to add about 16,000 and 1,600 megawatts (MW) per year, respectively, to keep pace with the combination of expected power demand increases and retirements of old power plants. The US case—16,000 MW (or 16 GW)—is equivalent to the output of 16 standard nuclear power units or 32 typical new coal-fired or natural gas–fired units (without CCS).* These additions must include a mix of generation technologies playing different roles.

- **Base-load** power units need to run at high utilization rates to spread their higher capital costs over more units of electricity.
- **Cycling** power units change their utilizations rates up and down routinely in response to variations in load.
- **Peaking** power units start up quickly to meet high, but infrequent, levels of power demand.

A combination of these generating technologies cost-effectively matches power supply to the expected variations in power demand through time.

Natural gas–fired technology can provide capacity to meet the technical requirements of all three power plant roles. Combustion turbine technologies provide peaking power supply, and combined-cycle technologies provide cycling and base-load power supply. So it is possible to

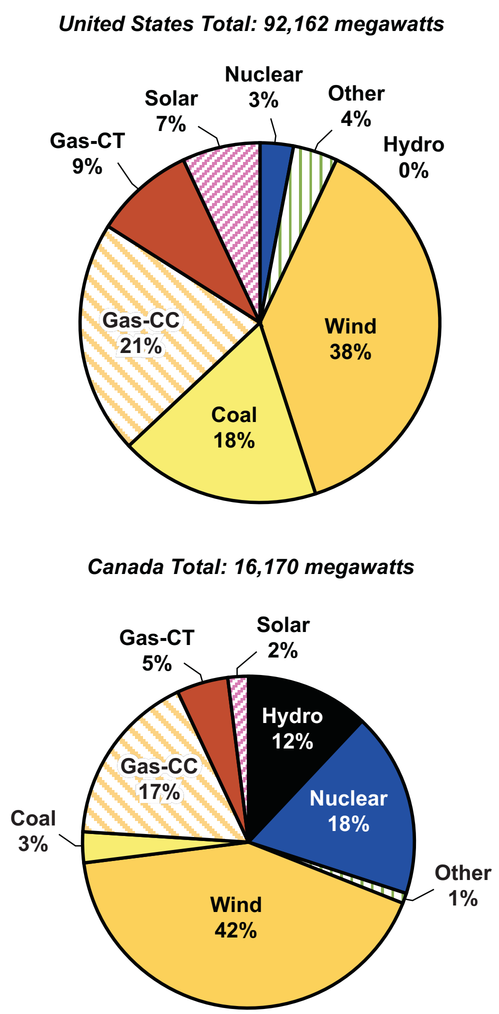
*The concept of a power unit, rather than a power plant, is used here since many plant sites have more than one type of unit—base-load, cycling, and peaking—all on the same power plant site. Also, most nuclear "plants" are built with two units per site to take advantage of economies of scale.

meet the *growth* in power demand exclusively with available natural gas–fired technologies. However, this would not only run counter to the basic strategy of fuel diversity; it would also increase the power sector's CO_2 emissions.

However, the need to slow GHG emission growth is already shaping current generating capacity addition plans. Planned additions for the next five years are shown in Figure VI-1. Power needs together with the proliferation of renewable portfolio standards mandated by states mean that the largest share of new nameplate capacity in the years ahead will be wind technologies.

Figure VI-1

Outlook for North American Power Generation Capacity Additions, 2010–14



Source: IHS CERA.
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Wind turbines have a significant advantage as a carbon-free generator of electricity. However, a significant drawback is that they provide little capacity that can be counted on to meet peak electricity demand. For example, in the Texas power system, wind resources make up the largest share of any regional power system supply portfolio in North America—and are discounted by over 90 percent when calculating the net dependable capacity to meet peak demand.

Thus, it is very important to understand that all capacity in electric power is not the same. Comparing the "capacity" of a wind farm against that of coal, natural gas, or nuclear capacity is really comparing the proverbial apples and oranges. Peaking and wind power plants both provide "intermittent" power. However, a combustion turbine provides its power when power system operators *call* for it, while a wind turbine produces power when wind conditions *allow* it.

When planning ahead, a North American power system that needs to expand supply and wants to meet incremental demand with wind resources must make a second investment decision. It needs to add nearly an equal amount of new dispatchable power resources (power that can be sent out when desired and needed) to back up the wind capacity. This capacity may normally run at a relatively low utilization rate, but it can be dispatched on short notice to fill in when the wind resources fall or are not available.

The typical annual utilization rate of wind turbines is around 30 percent. However, the average load factor of the US power system is 56 percent, and the backup generating capacity (for which natural gas–fired power plants are best suited) must provide the other roughly half of the generation requirement.*

Integrating solar power has similar challenges to integrating wind power. On the capacity side solar power capacity is discounted only about half as much as wind when calculating its net dependable capacity to meet peak demand—requiring only half as much backup capacity to firm up its capacity. On the energy side solar power capacity utilization rates are less than wind and average only around 20 percent.

These backup generation costs contribute to a 30 percent or more cost premium for renewable power generation to meet power demand growth—the primary reason that renewable power currently requires legislated mandates and production tax credits to be developed.

Integrating intermittent wind generation into a power system is easier and less costly when the power system already has excess cycling capacity in place or has significant natural endowments that provide storage, such as reservoir hydro or pumped storage capacity. Under these conditions there is little or no additional cost to firming up or filling in for wind capacity. However, such low-cost wind integration conditions are the exception rather than the rule. Most power systems do not have chronic oversupply of cycling capacity or large storage resources. Thus in the years ahead most North American power systems face challenges in integrating wind and solar.

*The wind turbine utilization rate is the ratio of the average power generation versus the nameplate capacity of the wind turbine. The power system load factor is the ratio of average demand load versus peak demand load.

If power demand growth were met with renewable power resources backed up by natural gas–fired generating technologies, the expected annual growth of power sector CO_2 emissions would be half that of expansions that were exclusively natural gas–fired technologies. However, such a scenario would also have to be supported by a very large investment in transmission to bring the power to load centers.

Power Investment Decisions: A Multiple-decade Planning Horizon

The technology and fuel investment decisions made today will have impacts on the generation fuel mix and the carbon footprint of the power sector for decades to come. The "power planning horizon" spans decades; just the time required for planning, permitting, and building a power plant can be a decade or more. In addition, once built, the planned engineering and expected economic life of a power plant are measured in multiples of decades. That means that the majority of generating plants that will operate a decade from now are already in place today.

Nuclear power provides a good example of the impact of this time frame on planning. A decision to build a nuclear plant affects not only the generation mix when it comes online but also the expected power sector fuel mix and associated GHG emissions for several decades beyond. Today 20 percent of the US generation mix is nuclear, a share consisting entirely of reactors that were ordered at least 30 years ago (compared with an expected 40 to 60 year operational life). In 20 years, most of today's nuclear fleet will still be operating. The current North American power sector fuel mix therefore reflects technology choices made over the past half century based on priorities that have changed with the times.

To maintain nuclear power's current 20 percent generation share beyond 2030, aggressive development will need to take place now to add at least 40 GW over the coming two decades, and even more to compensate for plant retirements. This urgency seems to be recognized—$8.3 billion of federal loan guarantees were announced for two new nuclear units in February 2010. In conjunction with that announcement, Carol Browner, White House Coordinator for Energy and Climate Policy, stated, "We are going to restart the nuclear industry in this country."

Not so long ago low costs and energy security were the top priorities; the carbon footprint of generating technologies was not a major concern. Moreover, when choices were made for many power plants operating today, a decade-long prohibition on the use of natural gas for new power supply was in effect following the passage of the Energy Supply and Environmental Coordination Act of 1974 and the Powerplant and Industrial Fuel Use Act of 1978. The result was a great surge in coal-fired capacity. Today preferences for the power sector have come full circle—natural gas–fired generating technologies make up a significant share of planned new power plant additions.

When the investment horizon spans multiple decades, as in the power industry, uncertainty about the future is an inescapable condition. Investment decisions must rely on outlooks, projections, and expectations. Fuel price expectations vary over time. In particular, natural gas prices have proved to be among the most challenging to predict over the years. In a review of its forecasting track record, the Energy Information Administration of the US Department of Energy found that, "The fuel with the largest difference between the projections and actual data has generally been natural gas."*

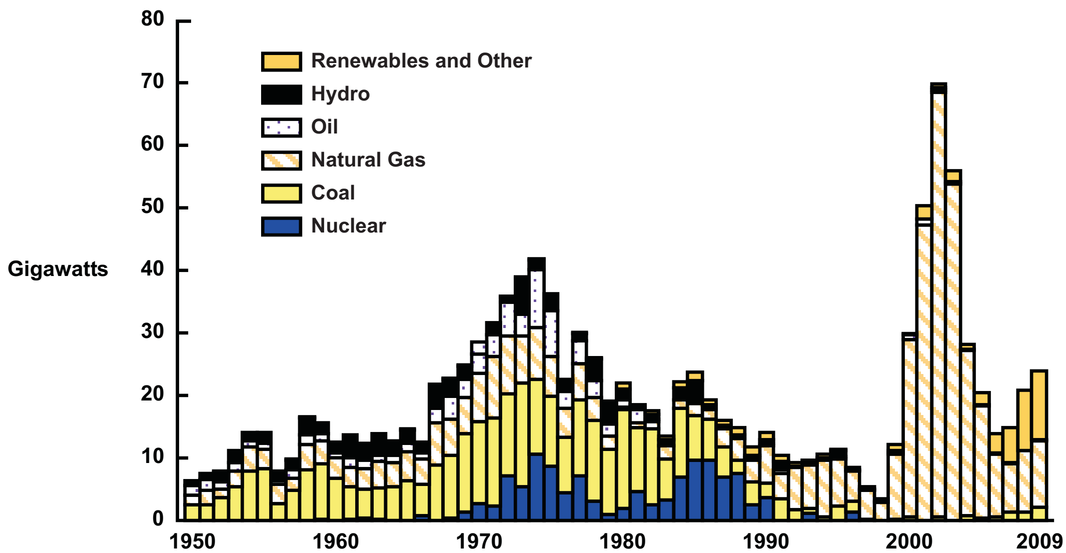
In 2006 high natural gas prices were expected into the future, and there was little activity to advance GHG legislation in North America. Under these planning assumptions coal-fired generation made up a large percentage of planned capacity additions.

The unconventional natural gas revolution has lowered the natural gas price outlook and made gas more competitive while encouraging higher expectations for security of supply—a dramatic shift from just half a decade ago. Furthermore most power producers have begun to expect that GHG limits in the future are less a matter of "if" than a question of "when and how much." Compliance with other pending environmental regulations, including replacements for EPA's struck-down Clean Air Rules, covering sulfur dioxide (SO_2), nitrogen oxides (NO_X) and mercury, as well as additional regulations governing ash disposal and water use, are expected to increase the cost of operating coal units.

The recent dramatic swings in technology and fuel choices for new power plants are nothing new. Figure VI-2 shows the technology selection for capacity additions from 1950 to 2009. Recent changes in expectations of future economic and regulatory conditions have swung the fuel and technology mix of planned power plant additions toward a larger natural gas

Figure VI-2

US Power Generating Capacity Additions, 1950–2009



Source: IHS CERA.
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*Energy Information Administration, Annual Energy Outlook Retrospective Review: Evaluation of Projections of Past Editions (1982–2008), September 2008, p. 2.

share. This change in expectations is one of the reasons that 48 coal plants were canceled or deferred in the last few years and in many cases replaced with plans for natural gas–fired capacity.

Transforming the Carbon Footprint of Existing Generation

Increasing the natural gas share of capacity additions can reduce power sector CO_2 emissions in the near and medium term. But it will only slow the growth in power sector CO_2 emissions over the long term. With the current power plant inventory there are four ways to reduce CO_2 emissions:

- fuel substitution in existing power generation
- conversion of coal-fired units to natural gas
- retirement and replacement of coal plants
- retrofit with equipment for CCS (discussed in Chapter VII)

Power plant utilization is determined by the decision to dispatch available generating resources to keep power demand and supply in balance at the lowest possible cost while maintaining system reliability. Power plants are ranked into a "merit order" based on their incremental costs for meeting changes in power demand, subject to transmission constraints and other technical factors. The result of this economic dispatch of power plants to meet load is shown in Table VI-1.

Fuel costs are a key factor in power plant utilization decisions. If the natural gas price becomes more favorable versus other fossil fuels, the expected share of gas in the power generation mix will be greater. The average utilization rate of US natural gas–fired power plants is 25 percent—an average consisting of some 40 percent for CCGTs, 10 to 15 percent for gas-fired steam boilers, and 7.5 percent for combustion turbines, The average utilization rate of coal-fired power plants is 73 percent. Coal plants are run more often for

Table VI-1

US Capacity Utilization Rates and Generation Shares, 2008

	GW	Capacity Share (percent)	Capacity Utilization Rate (percent)	GWh	Generation Share (percent)
Coal	313	31	73	1,994,385	49.8
Natural Gas	397	39	25	876,948	21.9
Nuclear	100	10	92	806,182	20.1
Hydro	97	10	29	248,085	6.2
Wind + Other	39	4	14	46,681	1.2
Oil	60	6	6	31,162	0.8

Source: IHS CERA and US Energy Information Administration.

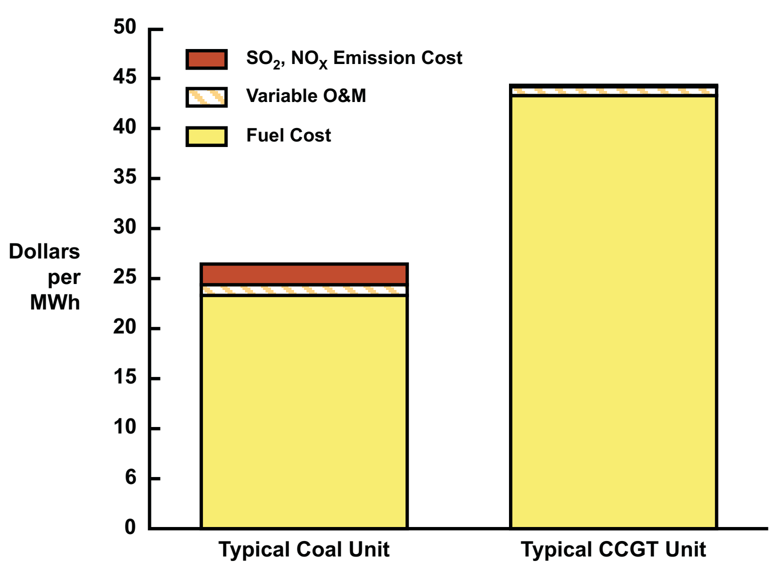
fundamental reasons—their incremental costs are typically lower. Based on the average delivered natural gas and coal prices across the first ten months of 2009 ($5.49 and $2.18 per MMBtu, respectively), the typical natural gas–fired power plant incremental generating costs were two-thirds greater than those costs for the typical coal-fired power plant (see Figure VI-3).

This is not unusual. The delivered cost of natural gas is typically between two and three times that of coal on an energy-equivalent basis. However, there is a gain on the gas side. The efficiencies with which coal and natural gas inputs are converted into electricity vary; but in round numbers each coal unit of input energy creates 0.4 units of electrical output compared with 0.5 to 0.6 units for natural gas—the higher efficiency being achieved with CCGTs.

The "shale gale" is expected to narrow, but not eliminate, the relative cost of using natural gas compared with coal. Although the price outlook has changed, and with it the expected generation share, the shift will likely remain within the range of the past several years. Figure VI-4 shows the relationship between natural gas price changes and fossil generation shares over the recent past. When natural gas prices decline relative to coal prices, the short-run costs of the most efficient natural gas units become more competitive with the short-run costs of the least efficient coal units, and the share of natural gas increases. With lower natural gas prices, the natural gas share of power generation should increase by several percentage points.

Figure VI-3

Typical Incremental Generating Costs: Coal versus Combined-cycle Gas Turbine (CCGT) Technology, 2009



Source: IHS CERA.
Notes: Fuel costs: coal = $2.18 per MMBtu and natural gas = $5.49 per MMBtu.
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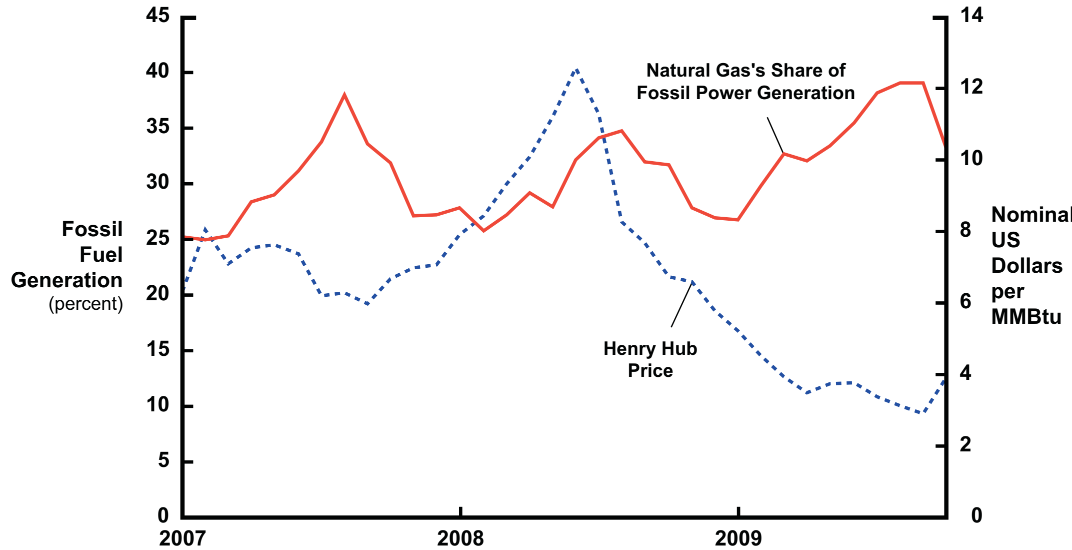
Figure VI-4

Natural Gas's Share of Fossil Power Generation versus Henry Hub Price, 2007–09



Source: IHS CERA.
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A greater share of natural gas in the fossil generation mix creates environmental benefits—CO_2 emissions are lower than they otherwise would be. Table VI-2 shows the typical CO_2 intensity of power production as fossil fuels generate electric energy with current technology. Every 1 percent shift in fossil generation from coal to natural gas reduces CO_2 emissions by a little more than half of 1 percent. A gain of several percentage points in the generation share because of lower natural gas prices would offset a few years' worth of expected growth in power sector CO_2 emissions.

Understanding the Gap

This leads to an often-asked question: Why can't the current natural gas fleet substantially replace coal in base-load generation? The natural gas–fired generating capacity is 27 percent greater than coal-fired generating capacity but is utilized only 25 percent of the time, compared with coal's 73 percent utilization rate (see Table VI-1). Theoretically, displacing all coal-fired generation with natural gas–fired generation would reduce power sector CO_2 emissions by 40 percent.

However, it is easy to misinterpret this gap between the actual utilization rate of natural gas–fired technologies and their technical maximum rate as "underutilization." It has always been true that, whatever the fuel, only a little more than half of the installed generating capacity in North America is needed to produce all of the electric energy (in megawatt-hours)

Table VI-2

Carbon Intensity of Fossil Fuel Electric Generation Technologies

(pounds of CO_2 emissions per kilowatt-hour)

Prime Mover	Coal	Petroleum	Natural Gas
Steam turbine	2.20	1.77	1.29
Combustion turbine	—	2.23	1.43
Combined cycle	—	1.87	0.92

Source: IHS CERA.

consumed in a year. However, this does not make half of the installed generating capacity surplus or underutilized. It is important to take into account the time pattern dimension of power consumption—as in the discussion of peak load and intermittent generation, above.

Power systems need plants that run at less than maximum rates to maintain system reliability and to serve the peak demand, rather than the average demand. Average demand is just a little more than half the level of peak demand, and hypothetically there is enough non–coal-fired capacity available to equal average demand. However, eliminating the coal-fired capacity would leave only enough capacity to supply average demand. There would be no capacity available to meet above-average demand, which occurs roughly half the time. A 50 percent shortfall to maximum demand would be catastrophic to power system operations—even a 1 or 2 percent shortfall in supply is sufficient to cause brownouts, and blackouts result beyond that point.

The need is clear—in addition to base load, power systems require both peaking and cycling power plants. Utilization rates of natural gas–fired technologies—combustion turbines, CCGT, and boilers—reflect their application to these generation roles.

- **Combustion turbines account for about one third of US natural gas–fired installed capacity and are utilized as peaking power plants with an average plant factor of 7.5 percent.**

- **CCGTs account for roughly half of installed natural gas capacity, playing various roles and an average plant load factor of nearly 40 percent.** About one third of these combined-cycle power plants operate as peaking plants with annual plant factors below 30 percent. Over half operate as cycling plants with annual plant factors above 30 percent and below 70 percent. Only about 15 percent of combined-cycle power plants currently run in base-load applications with annual plant factors above 70 percent.

- **The remaining one fifth of installed natural gas capacity burns natural gas as a boiler fuel and generates power from steam turbines.** These plants have an average load factor between 10 and 15 percent.

The technical problem in trying to reverse the roles of natural gas– and coal-fired power plants is that over two thirds of natural gas–fired power plants run as peaking units. Coal-fired power plants cannot start up fast enough or ramp up and down easily over a wide enough range of capacity factors to fill in for the peaking roles played by natural gas–fired technologies.

Reversing the roles of coal- and natural gas–fired power plants in cycling applications is also highly constrained by limits of existing transmission grids. In most cases natural gas plants are not in proximity to coal plants and lack the power transfer capability to act as direct substitutes for regional electricity needs. It is striking that almost half of all natural gas–fired generation is located in only three states—Texas, California, and Florida. Indeed from a transmission perspective, Texas is close to being an electrical island because its alternating current production is not synchronous with production in neighboring transmission systems. Florida also suffers from transmission bottlenecks due in large part to its peninsular geography. In contrast, coal generation is concentrated in the Midwest, where natural gas–fired generating facilities are sparsely distributed.

Power transfer bottlenecks are also quite location specific. As a result, plant location and the need for grid stability constrain the possibilities for reversing the roles of natural gas and coal plants.

Given all these constraints opportunities for natural gas to substitute for coal in the existing power mix are quite limited and costly. Table VI-3 shows that a CO_2 emission price around $30 per metric ton would be necessary to close the incremental cost gap between most existing natural gas– and coal-fired power plants. Under these conditions economic dispatch pushes fuel substitution above a 10 percent shift away from coal-based generation to natural gas. This would result in about a 5 to 10 percent reduction in power sector CO_2 emissions—enough to offset some four years of expected power sector emissions growth.

Power Plant Retirements and Replacements

Any significant replacement of existing coal-fired power plants in the near term requires building new natural gas–fired power plants. There may also be some opportunity to convert existing coal-fired plants to burn natural gas. Current natural gas price expectations lower the estimated costs of a new natural gas CCGT plant and thus reduce the cost of replacing an existing coal-fired power plant. However, this does not eliminate the cost hurdle; the unconventional gas revolution by itself is not likely to trigger an acceleration of expected coal-fired power plant retirements.

Retirement and replacement of an existing generating technology only make economic sense when expectations of the entire cost—both fixed and variable—of a new replacement technology are lower than the projected "going forward" of the existing power plant.

Power plants have long economic lives in part because power production is a capital-intensive process. Capital costs are largely fixed costs—they do not vary with production. In power generation, capital costs make up the bulk of sunk costs—costs that cannot be

Table VI-3

CO_2 Emissions Price Needed to Close Typical Incremental Generating Cost Gap

	Typical Coal Unit	Typical CCGT Unit
Size (MW)	500	500
Heat rate (Btu per kWh)	10,700	7,900
Fuel cost ($ per MMBtu)	2.18	5.49
Fuel cost ($ per MWh)	19	47
Variable O&M ($ per MWh)	1.1	0.9
Fixed O&M ($ per MWh)	4.1	1.3
SO_2 per MWh (with wet flue gas desulfurization) (lbs)	3	0
SO_2 allowance price ($ per ton)	80	80
NO_X per MWh (lbs)	2	0.2
NO_X allowance price ($ per ton)	1,646	1,646
SO_2, NO_X emission cost ($ per MWh)	2.1	0.1
CO_2 per MMBtu (lbs)	205	118
CO_2 per MWh (lbs)	2,194	932
CO_2 price ($ per ton)	**29**	**29**
Short-run marginal cost ($ per MWh)	22	48
CO_2 cost ($ per MWh)	44.4	18.9
Total short-run marginal cost ($ per MWh)	**67**	**67**

Source: IHS CERA.

avoided whether the plant runs or not. This high hurdle for economic replacement of existing generating technologies is the primary reason that power plants operate for many decades even if improved technologies are available that offer higher operating efficiencies.

Since power production is so capital intensive, the retirement and replacement hurdle is typically hard to reach. For example the typical existing coal-fired power plant has going-forward costs per megawatt-hour that are two thirds lower than the capital and operating cost per megawatt-hour of a new CCGT—the most cost-effective replacement for a retiring coal-fired plant. Carbon prices or power plant performance standards, if sufficiently stringent, would make it easier to overcome this hurdle.

Furthermore, in some cases, the retirement hurdle may be lowered when other capital spending decisions—particularly some environmental retrofit investments—are part of the going-forward costs at an existing coal-fired power plant.*

THE POWER QUANDARY

The transition to a low-carbon future creates a quandary for the power sector. In the short term, projections of abundant unconventional natural gas resources have lowered natural gas price expectations and improved the security of fuel supply outlook. Natural gas as a power

*Today, roughly 45 percent of coal-fired power plants are equipped with postcombustion pollution control technology for SO_2 and NO_X emissions. In the near term additional controls are expected to be installed to meet more stringent standards for SO_2 and NO_X emissions and to comply with pending mercury emissions regulation.

generation fuel emits half the CO_2 of coal. Together these three factors encourage greater use of natural gas for power generation. But the unconventional revolution has not altered the carbon content of natural gas—challenging increased fossil fuel use by the middle of the century, when requirements for significant GHG emission reductions could be in place.

GHG regulation seems to be an inescapable issue for the North American power sector, whatever its final form, as power accounts for about 40 percent of North American GHG emissions. Current expectations are that US GHG emissions will continue to trend upward in the absence of any additional federal legislation or regulation. Any policy that reverses that trend will have a major impact on the power sector.

Climate change policy decisions are the key to resolving the quandary and determining the impact of the unconventional natural gas revolution on fueling the future North American power sector. A wide range of policy options are being considered today.

NATURAL GAS AND COAL FACE SIMILAR LONG-RUN CHALLENGES AND A NEED FOR CCS

Aggressive use of natural gas, via coal-to-gas switching (within limits), converting existing coal-fired plants to some gas-fired plants, and replacing existing coal plants with new gas-fired plants could deliver CO_2 reductions for the coming decade or two. But long-term CO_2 reductions, particularly strong reduction requirements such as the often-cited 80 percent by midcentury, would not allow for growth in gas-fired power generation beyond the next two decades unless CCS with gas is viable and competitive with nuclear and coal with CCS.

In a severely carbon-constrained world, currently anticipated in the long term, nuclear and CCS become critical. Although nuclear is an established technology, the long lead times for building nuclear power plants require decisions on new capacity to be taken today. As discussed in the next chapter, CCS requires time to be established as viable at utility scale and, further, requires long lead times for deployment.

Because the long-term future of gas-fired power plants is uncertain, depending on the stringency of climate change policy and the viability and cost competitiveness of CCS, some are concerned with the possibility that today's new gas-fired power plants may not run for their intended life spans. Even though power generation is very capital intensive in general, CCGT plants are the least capital intensive among base-load technologies. This makes them somewhat resilient to uncertainty about their expected life spans.

One version of the quandary therefore boils down to this: Should power companies build CCGT plants, which are much easier to permit and quicker to build, and take the risk that these may be unable to operate for their planned technical life span because of the encroachment of GHG emissions limits? Or should they build nuclear power plants, which are more expensive, take longer to build, and are more difficult to permit yet are not subject to this risk but may turn out not to have been necessary if GHG emissions limits are less stringent than currently proposed?

The state of technology or the availability of offsets may change and alter future fossil-fired carbon footprints. CCS technologies are under development. If these technologies become technically feasible at utility scale and economically viable for either or both coal and natural gas–fired power generation, the future path of fossil fuel use for power generation may develop quite differently.

We discuss the scale of the challenge for CCS and the outlook for its deployment in the next chapter.

CHAPTER VII: CARBON CAPTURE AND STORAGE— UNDERSTANDING THE SCALE AND RISKS

CHAPTER VII: CARBON CAPTURE AND STORAGE—UNDERSTANDING THE SCALE AND RISKS

- If the often-mentioned 80 percent reduction target for carbon dioxide (CO_2) emissions are to be met, either fossil fuel usage—including natural gas—will have to be dramatically reduced or carbon capture and storage (CCS) will be required.
- The state of technology for CCS needs to advance significantly if it is to be cost competitive with clean energy alternatives such as nuclear or hydropower.
- Commercial, utility-scale CCS has not been demonstrated. The scale of North American CO_2 daily emissions from the power sector alone (in dense phase, "liquid" conditions) exceeds three quarters of global daily oil supply volumes.
- Policy to deal with legal liability and pore space ownership issues will be required just as much as support for expansion of research and development (R&D) efforts to demonstrate utility-scale CO_2 injection.

More than 80 percent of primary energy demand in North America is fossil fuel based. The installed infrastructure would cost trillions of dollars to replace. Despite targets and policies for promoting non–fossil-based energy supplies, the sheer scale and complexity of the system would require many decades to replace the reliance on fossil fuels. This reality is reflected in expectations of the continued role of fossil fuels. For example, in its baseline scenario the International Energy Agency (IEA) projects, that global primary energy demand will double between 2005 and 2050 and, in fact, include a growing contribution from fossil fuels.* Even in the most optimistic outlook (the IEA's BLUE Map scenario), fossil fuel usage falls in absolute terms by only 13 percent from 2005 levels. Aggressive demand reduction and other mitigation strategies appear able only to halt the growth of fossil fuel usage. (In other scenarios, a nuclear renaissance or a much more rapid development of renewables would reduce the carbon content of the power sector. But the path to rapid deployment is not clear.) These levels of fossil fuel usage seem to be at odds with plans to reduce global GHG emissions by some 80 percent by 2050.

How can these two propositions coexist? The only obvious answer today seems to be the successful widespread deployment of CCS. Most projections of the fuel supply portfolio indicate that by the middle of this century CO_2 emission targets cannot be met without large-scale deployment of CCS. In its widely cited application, as its name implies, CCS involves the "capture" of CO_2 in one way or another from fossil fuels. The CO_2 is transported to and injected into an underground site where it is "stored" and thus sequestered so it does not enter the atmosphere.

The engineering behind capture, transportation, and injection of CO_2 is not new. Natural gas plants and other processing facilities around the world routinely capture acid gases (CO_2 and hydrogen sulfide). In some instances those plants have also injected these captured acid gases into secure formations deep underground for many years. It has also been used

*Sources: IEA *Energy Technology Perspectives 2008: Scenarios and Strategies to 2050* and *World Energy Outlook 2009.* The US Energy Information Administration's *International Energy Outlook 2009* and Massachusetts Institute of Technology's *The Future of Coal* (March 2007) show similar trends.

as a way to enhance oil recovery. Over the past several decades in the United States alone some 600 million metric tons (mt) of CO_2 has been safely injected into mature oil fields to drive additional oil recovery.

But applying these technologies to low-pressure streams such as power station exhausts is very expensive. Furthermore the scale of CCS from power plants will likely require new regulatory regimes to deal with ownership, liability, and safety of underground storage. Perhaps the development of some form of "eminent subdomain" will be needed to cut through the issues that will arise. In contrast to the traditional NIMBY—"not in my back yard"—hurdle, CCS has already given rise to a new concept: NUMBY—"not under my back yard."

CCS has been neither proved nor demonstrated at anything like the scale required for decarbonizing the electric power supply in North America, let alone the rest of the world. Such demonstration at scale does not appear likely in any near-term time frame. But it is a focus of enormous activity. R&D spending on both technology breakthroughs and operational performance improvements by governments and industry alike runs to billions of dollars. This is a reflection of how critical the successful, cost-competitive deployment at utility scale of CCS will be to meeting future GHG emissions targets.

The CCS cost challenge is an engineering challenge—about heavy-duty, large-scale process engineering where the impact of innovation is to shave a few percent off the cost or weight of a reactor vessel or to drive a few percent of process efficiency improvement. Success in deploying CCS may result from a transformational innovation: the use of membranes to separate oxygen or CO_2, or new chemicals that dramatically improve the efficiency of the processes. Or instead it may be a series of steps along the path of relentlessly squeezing cost and performance improvements out of large-scale chemical engineering facilities.

Although the focus of this chapter is sequestering the emissions of the electric power industry, there are a number of other sources of CO_2 where CCS could be applied, and this leads to a range of costs for different steps of the CCS process. We return to the costs of CCS later in this chapter.

Both government and industry believe they can see a pathway to success, albeit strewn with risk factors. Yet without sustained R&D funding and public and political support, it may take longer to arrive at the destination than the 10 to 20 years anticipated in some analyses of the pathway to a low-carbon future.*

Three main approaches are being considered for reducing CO_2 emissions from fossil-fueled power generation.

- **Precombustion, where CO_2 is removed from synthetic gas (or "syngas") to leave pure hydrogen as the fuel.** This part of the process has been proved at scales over 250 megawatts (MW) in gas processing and coal gasification applications but not in utility-scale power generation with CCS.

*EIA *Energy Market and Economic Impacts of HR 2454, the American Clean Energy and Security Act of 2009* (August 2009).

- **Postcombustion, whereby CO_2 is separated from nitrogen in the exhaust gases.** This has been demonstrated at a 20 MW scale, capturing 100,000 tons of CO_2 per year.

- **Oxyfuel combustion, whereby the nitrogen is stripped out of combustion air to leave nearly pure oxygen.** This is then combined with sufficient recycled CO_2 to create appropriate furnace conditions, and the exhaust gas of pure CO_2 can be more easily captured and compressed. This is being demonstrated at a 30 MW scale.

Demonstrations of underground storage of CO_2 have also proved to work reliably at commercial scale (including the Weyburn project in Saskatchewan, the Sleipner and Snøhvit projects in Norway, and In Salah in Algeria). But there are no examples of all the steps of the CCS process in an integrated power generation system being proved to work reliably at the scale required nor to be cost effective at current CO_2 emissions prices. Yet this does not mean that ongoing R&D will not lead to a successful, economically viable outcome.

MEETING EMISSIONS TARGETS—THE NECESSITY FOR CCS

The scale of the challenge in the United States alone is daunting. The entire US economy's annual GHG emissions are some 6 gigatons of CO_2 equivalent. Approximately a 40 percent contribution (2.5 gigatons of CO_2) comes from the electric power sector. Oil's contribution in the power sector is negligible—it generates less than 1 percent. Coal and natural gas usage provides almost the entire CO_2 emissions in the power sector in a ratio of 80:20. That is 2 gigatons from coal-fired generation and 0.5 gigatons from natural gas–fired generation.

As noted in the previous chapter, this latter quantity is equal to the implied maximum 2050 target emissions, in the absence of offsets, for the entire US power system even before considering electricity demand growth.

The CO_2 output of a fossil-fueled plant is vast in volume terms, yet it is hard to conceptualize what this actually means. It may be helpful to compare these volumes to other quantities:

- One gigawatt (GW) of coal-fired power stations, generating about the amount of electricity used by 650,000 homes, emits nearly 1,000 tons of CO_2 each hour that plant is running at full capacity.

- At the average 73 percent US coal-fired power station load factor, this is a little over 6 mt per year of CO_2 for 1 GW of installed capacity.

- This gas would become a volume of some 125,000 barrels per day when compressed to dense phase, supercritical conditions (similar to a high-pressure liquid state).

- This represents a processing plant as large as half the production capacity of the largest offshore oil production facility in the Gulf of Mexico.

- The output each year (if injected into a formation 100 feet thick) would likely occupy an area of more than 10,000 acres.*

*This figure is based on a porosity of 10 percent, with the CO_2 occupying 5 percent of the gross pore space.

- Over a 60-year life of a coal-fired power station this may require an area approximately the size of Rhode Island.

And all of this from just one power station out of a total of more than 300 GW of coal-fired power stations in the United States. If one considers the entire installed fleet of coal-fired power stations, the volume of liquid CO_2 generated would be approximately 37 million barrels per day (mbd)—more than the entire oil production of OPEC. And it is not just coal-fired power stations that emit CO_2. The CO_2 output of the current 400 GW US gas-fired generating fleet (operating at a 25 percent load factor) would be about 9 mbd—more than the entire oil output of the United States and Canada.

As we discuss below, for a retrofit application of postcombustion carbon capture, the energy load required to capture and compress the CO_2 output of these power stations reduces the output to some 70 percent. In other words there will need to be 35 percent more power stations built just to cover the electric power lost from carbon capture. If this additional capacity were natural gas–fired power stations, it would raise the volume of CO_2 captured for storage to more than 60 mbd—almost three quarters of current global oil production. These volumes are based on today's demand profile. Any growth will only increase the scale of the challenge.

The experience of the oil industry is often cited as a guide to CCS. There is considerable history of CO_2 being injected at high pressure into wells for enhanced oil recovery (EOR). A portion of the CO_2 mixes with the oil, increasing its volume and reducing viscosity, making the oil easier to recover. The CO_2 produced with the oil is separated and recycled back into the reservoir. The remaining CO_2 stays in the pore spaces vacated by the produced oil, and over time the reservoir fills up with CO_2. In this situation the volume of CO_2 that can be stored is approximately equal to the volume of oil produced—the 1 GW of power example above would require an oil field that had produced reserves of more than 2.5 billion barrels, or 6 trillion cubic feet of gas, over its life.

Not all oil fields respond to EOR through injection of CO_2, but even if they did, the opportunity is not on a scale even approaching power sector emissions, and the potential reservoirs are not located conveniently near the power stations. The alternative proposal is to inject CO_2 into deep underground saline formations, assessed as being located within a minimum of 25 miles of each power station.* In this case the proportion of the pore space that can be used is limited by the ability to displace the saline water already in the aquifers and could also lead to the very large reservoir areas noted in the example above. Nevertheless some estimates of the volumes of pore space available for CO_2 storage indicate sufficient capacity for several hundred years' of emissions—more than would be required for all currently identified reserves of fossil fuels.

This is not just a technical problem to be overcome but requires a regulatory system to apportion liabilities to those best able to manage them over the long term and to clear the ownership path for using the pore space underground. Obviously there would be a trade-

*National Energy Technology Laboratory (NETL), *Coal-Fired Power Plants in the United States: Examination of the Costs of Retrofitting with CO_2 Capture Technology and the Potential for Improvements in Efficiency*, December 2009.

off between the costs of transporting huge volumes of CO_2 over long distances to more easily secured (and less diversely owned) storage sites versus requiring more extensive and potentially complex local storage.

OVERVIEW OF TECHNOLOGY APPROACHES TO BOTH CAPTURE AND STORAGE

There are three major approaches being explored for the CC component of CCS. To date only one approach is favored for the "S" component—underground storage.

Postcombustion Capture

Postcombustion capture involves passing the entire exhaust stream from a power station (for coal-fired generation, this would contain 10–15 percent CO_2) through a chemical solvent column. The CO_2-laden solvent is then regenerated to remove the CO_2 into a concentrated stream of gas that can be compressed to liquid form at high pressure for storage (see Figure VII-1). This type of approach removes up to 90 percent of the CO_2 emissions of the retrofitted power station. But it reduces the net power output by approximately one third, because the CO_2 removal and compression equipment uses energy and power that would otherwise be available to the grid. In other words a retrofitted 1 GW power station with postcombustion CO_2 removal will be able to provide a peak load of less than 700 MW after carbon capture equipment is installed.

Precombustion Capture

Precombustion capture involves converting the fuel into syngas (a combination of hydrogen and CO_2) using a gasifier and a shift converter (see Figure VII-2). The higher concentration of CO_2 in the syngas—around 40 percent—and its higher pressure allow the gas to be more easily removed with a lower energy penalty than for postcombustion capture (about 20 percent). Like postcombustion capture, precombustion capture will remove up to 90 percent of the CO_2 emissions. In general this technology cannot be cost-effectively retrofitted to an existing power station, and so it likely applies only to new generation. It will not, therefore, have a wide application in the next decade, nor likely before 2030, since widespread adoption is unlikely before results from initial pilot plants have been reviewed and incorporated.

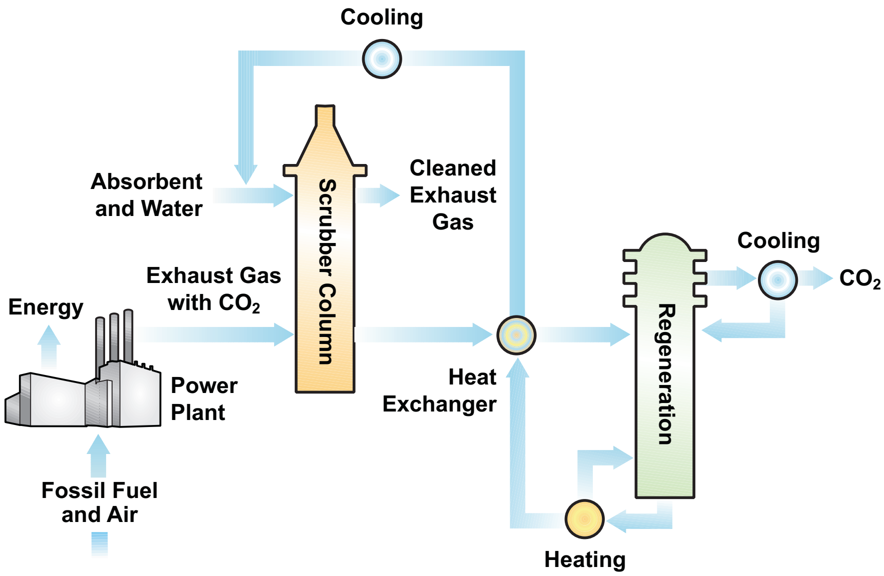
Current research initiatives for reducing the cost of precombustion carbon capture include the use of fuel cells and combinations with cogeneration applications. The production of syngas generates heat that can be recovered to improve the economics of the system.

Oxyfuel Combustion

Oxyfuel combustion involves cryogenically removing the nitrogen from the intake air. Some of the exhaust CO_2 is recirculated to create an appropriate combustion environment—burning coal in pure oxygen presents challenges. Then after condensing the water vapor and removing pollutants and particulates from the exhaust gases, a nearly pure stream of CO_2 is captured (see Figure VII-3). The combined energy requirements of the cryogenic air separation plant and CO_2 compression use up some 25 percent of the rated capacity of the

Figure VII-1

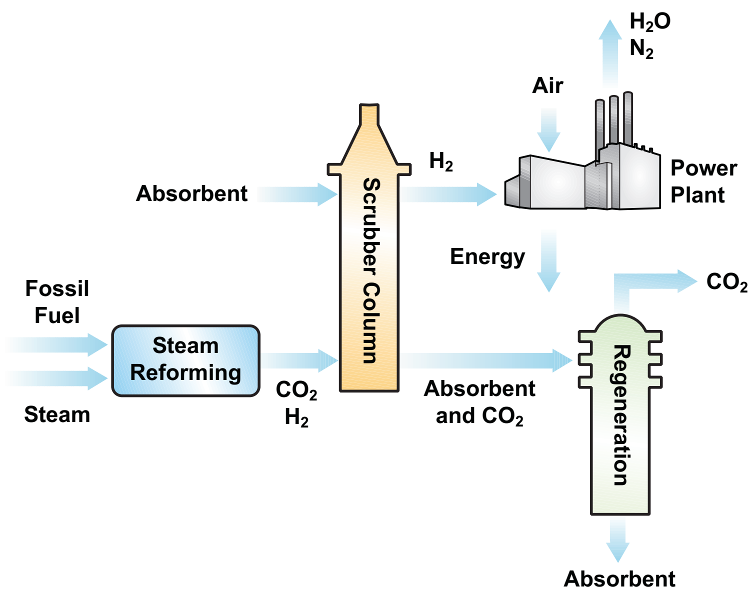
Postcombustion Carbon Capture Process



Source: IHS CERA.
91114-1

Figure VII-2

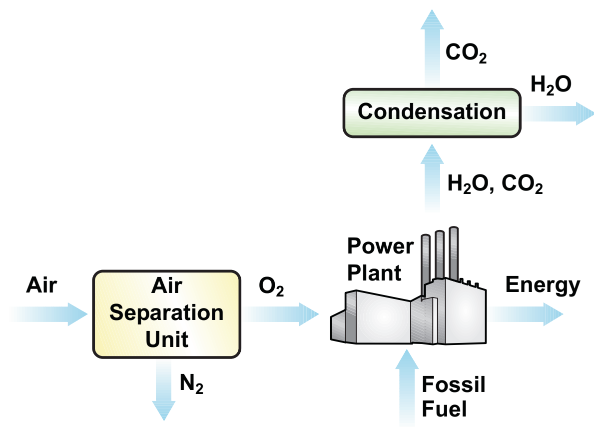
Precombustion Carbon Capture Process



Source: IHS CERA.
91114-2

Figure VII-3

Oxyfuel Carbon Capture Process



Source: IHS CERA.
91114-3

power station—slightly less than for postcombustion carbon capture. Oxyfuel combustion provides the highest degree of CO_2 capture—approaching 100 percent—and can, under some circumstances, be retrofitted. However, the extent of the retrofit and its likely lower efficiency than a new plant will favor new build applications.

Small-scale demonstration plants for the postcombustion and oxyfuel combustion approaches are already either operating or under construction, but, as Table VII-1 indicates, all of these demonstrations are at approximately one tenth of the scale required for widespread deployment. There are also plans for further demonstrations of precombustion technologies. There are commercial examples of syngas plants, but integration with a hydrogen-fueled turbine in a load-following power plant and CO_2 storage has not yet been demonstrated at scale.

Cost Estimates for Carbon Capture Technology Approaches

IHS CERA has prepared engineering cost estimates for each of the above approaches to utility-scale carbon capture—using an assumption that CCS technologies can be scaled up linearly by a factor of ten.

For postcombustion technologies the cost of building a new 1 GW net output carbon capture–capable coal-fired power station would be 75 to 80 percent more than the cost of a conventional coal-fired power station, bringing the total cost to approximately $4,600 per kilowatt (kW) at current prices. This consists of the additional process equipment to remove 90 percent of the plant's CO_2 output and the extra cost of building a larger plant to provide the additional power required to run the carbon capture equipment. The fuel consumption rises by 40 to 45 percent.

The costs of oxyfuel plants with carbon capture are a little lower—approximately $4,300 per kW—and fuel consumption rises approximately 30 percent.

Table VII-1

Global Integrated Power Generation with CCS Demonstration Activities—Still at Pilot Scale

Project (capture technology)	Location	Size	CO_2 Sequestered (million tons per year capture rate)	Start-up Year	Status	Leading Participant(s)
Schwarze Pumpe (oxy-lignite)	Germany	30 MWt	0.06	2008	Operating	Vattenfall, Alstom
Hazelwood (postcombustion)	Australia	NA	0.01	2008	Operating	International Power, Alstom
Pleasant Prairie (postcombustion)	United States	5 MW	0.02	2008	Operating	We Energies, Alstom, EPRI
Lacq (oxy-gas)	France	30 MWt	0.07	2009	Operating	Total, Alstom
Mountaineer (postcombustion)	United States	30 MWt	0.1	2009	Operating	AEP, Alstom
Callide A (oxy-coal)	Australia	30 MWe	0.02	2011	Construction	CS Energy

Another 50+ integrated projects and 15 storage-only projects are under various stages of development.

Source: IHS CERA.
Note: MWe = megawatts electrical; MWt = megawatts thermal.

The cost of retrofitting a postcombustion technology will be even higher than to build it as part of a new plant. The constraints and compromises of the existing plant footprint and of tying the new process equipment into an existing facility that was not built for this purpose all add to the cost. The result is that costs of retrofitting will be a further 10 to 50 percent higher. At the upper end of the range it might be more cost effective to build new.

By contrast the cost of a precombustion CO_2-capturing coal-fired power station adds approximately 70 percent to the cost of a conventional plant without carbon capture. The energy consumption is only 20 percent higher. No retrofit option is economically practicable with precombustion technologies.

Though the main focus of this chapter is CCS for power generation, a number of applications in other sectors may present more cost-effective and technically achievable opportunities. Figure VII-4 illustrates the range of costs synthesized by integrating a number of different data sources.

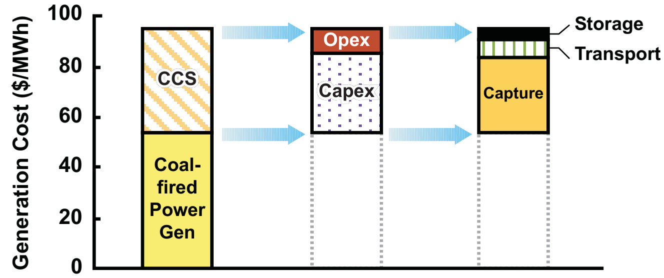
Figure VII-4

CCS Costs

CCS Cost Drivers

- Size of CO_2 source
- CO_2 concentration
- CO_2 pressure
- Maturity of technology
- Proximity to and quality of storage

DISTRIBUTION OF CCS GENERATION COSTS (coal)



2009 Costs ($ per ton CO_2 stored)	*Capture + Compression*	*Transportation*	*Storage*	*Total Cost*
Low Cost	Gas processing: $10–$25	At site: $0	EOR or EGR: ($10–$30)	($20)–$15
Medium Cost	Coal power plants: $60–$120	30–200 miles: $2–$10	Depleted oil/gas field: $5–$10	$70–$140
High Cost	Refining, air: $100–$1,000+	>500 miles: $15–$25	Offshore saline: $20–$30	$140+ Likely >$500

Sources: IHS CERA, US Department of Energy, NETL, and industry sources.
00112-25

THE VIABILITY OF CO_2 STORAGE

In all three carbon capture formats the output from the power plant is a high-pressure stream of supercritical liquid CO_2 ready for injection into underground storage. As we have already outlined, the volumes involved are vastly larger than can be used by enhanced oil recovery operations. Where, therefore, can the CO_2 be stored? Current planning in Alberta is for injection into depleted oil and gas fields. Elsewhere, in the absence of conveniently located depleted reservoirs, the base case is for injection into deep saline formation as referenced in the NETL study cited earlier in this chapter.

Not all subsurface rock formations are suitable for injection of liquids on a long-term sustainable basis. They must exhibit both porosity and permeability—the former being space between the grains that make up the rock and the latter describing how easily fluids can flow between the pore spaces. Not all sedimentary rocks exhibit both porosity and permeability, and it is not possible to determine which are suitable without expensive drilling to test the formation properties.

As a general rule CO_2 would be injected at least 2,500 feet below ground under a suitable confining structure that would keep the supercritical CO_2 trapped for thousands of years. The deeper a formation is buried (or has been buried in the past), the lower the porosity and permeability. For example the range of porosities that might be expected would be from 5 to 15 percent. There seems to be broad consensus that injected volumes will not exceed 5 percent of the available pore volume, so each cubic meter (1,000 liters) of rock formation will be capable of accommodating between 2.5 and 7.5 liters. Some estimates suggest that injected CO_2 will be able to occupy only between 2 and 3 percent of the pore space and that the number of injection wells could run from 5 to 100 for each gigawatt of fossil-fueled power.

It is still too early to confirm whether this is actually the case—it will require drilling into each potential storage site to confirm its long-term capability for injection and storage. Until large-scale injection over an extended period of time has been demonstrated, the range of estimates of what can be achieved varies widely. But even if 100,000 wells were required, this would not be insurmountable when considered in light of the 36,000 wells drilled in the United States in 2009.*

Estimates for the cost of each injection well, including the long-term monitoring instrumentation to ensure the integrity of the CO_2 storage, lie in a range between $5 million and $50 million. These must be added to the cost of the distribution pipe work to take the CO_2 from the power station to the injection wells (potentially spread over an area of 1 million acres), the costs of accessing the pore space, and the proportionate share of the carbon capture facilities at the power station.

If costs are reduced by successful innovation in this large-scale chemical and process engineering endeavor, CCS may be a cost-competitive option compared with nuclear power—currently the only large-scale, commercially proved source of zero-carbon thermal power supply. But the costs of nuclear power represent the base case at which new CCS technologies can aim. These alternative technology approaches range from creating solid carbonates for storage to capturing the CO_2 in a new hydrocarbon fuel cycle.

In conclusion CCS should be viewed as technically feasible, critically needed, but not yet economically viable nor demonstrated at the required scale. The size of the undertaking in North America alone is very large compared with the existing hydrocarbon production value chain, and the time frames for implementation are longer than are commonly recognized. The heavy processing equipment required to capture and store future CO_2 emissions will likely need to process fluid volumes larger in scale than the entire North American oil and gas industry today. The challenges of building out this infrastructure will be a strenuous and demanding test of the entire North American supply chain.

*See US Energy Information Administration, *U.S. Crude Oil, Natural Gas, and Dry Exploratory and Developmental Wells Drilled.*

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