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Fueling the Future with Natural Gas:

Bringing It Home

January 2014

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Executive Summary

In Brief

- Unconventional technologies have dramatically altered the outlook for US natural gas over the past five years. Once considered to be in imminent danger of depletion, the US natural gas resource base is now widely agreed to be sufficient to last 100 years at current rates of consumption. Costs have also fallen, and the natural gas price is expected to grow very slowly over the next 20 years, remaining much lower than prices for many other fuels.
- The new outlook for natural gas cost and availability has created new possibilities for making progress toward national goals of energy efficiency, cost efficiency, environmental protection, and energy security. It is also contributing jobs and revenues to the economy at the national, state, and local levels.
- Gas local distribution companies (LDCs) face both opportunities and challenges in helping their communities take advantage of newly abundant supplies of natural gas. Specific opportunities will vary from one region to another and may require regulatory change, policy support, financial and technological innovation to be fully realized.
- Much prevailing natural gas regulation was developed in a time of perceived scarcity and should be reviewed to identify areas that may no longer be appropriate for today's and tomorrow's gas markets.
- State governments, public utility commissions (PUCs), and gas LDCs should consider how natural gas can help improve total energy efficiency, reduce emissions and lower costs, using full fuel-cycle analysis for a more accurate assessment and comparison of various fuels and technologies.

It is called a revolution for a reason. In the span of less than five years, unconventional technologies for natural gas development have changed the outlook for US natural gas supply from scarcity to abundance, from high cost to moderate cost, from import dependence to self-sufficiency. Turning this revolution to best advantage requires both vision and understanding on the part of gas local distribution companies, their customers and regulators. Business models, fuel choices, regulation, and energy policy must be re-evaluated in light of the new opportunities presented by the unconventional natural gas revolution.

These opportunities are both immediate and far-reaching, as evidenced by the current natural gas surplus and the new understanding that the domestic natural gas resource base will be sufficient for domestic needs for many decades. A visionary response to these opportunities must therefore encompass both the near- and long-term perspectives. This report begins that process by evaluating the opportunities to leverage customer-based knowledge, critical infrastructure, regulatory and policy relationships, and the extraordinary natural gas resource availability to realize the benefits of natural gas for gas LDC customers and the nation as a whole:

- Technology, efficient applications and economic opportunity have dramatically altered the outlook for domestic natural gas for decades to come. Once considered in imminent danger of depletion, the US natural gas resource base is now widely accepted to be robust and recoverable at a lower cost than could have been imagined even five years ago.

- Extensive volumes of natural gas can be economically developed in the United States with prices of less than $4-5 per million British thermal units (MMBtu), making supply responses to demand increases highly elastic. Domestic and international oil prices are expected to remain three to four times higher than the British thermal units (Btu) equivalent price of natural gas for many years into the future. Also new high-efficiency natural gas technologies and a widening gap between retail prices of electricity and natural gas in many US regions give natural gas the competitive edge for many residential and commercial applications.

- This reality opens many doors for efficient use of natural gas resources and infrastructure in critical areas of the US economy and quality of life, including cleaner electricity generation and direct use in businesses, homes, transportation and manufacturing.

- Increased use of natural gas in the national energy economy will help achieve national goals of energy efficiency, environmental protection and energy security.

- Unconventional oil and gas activity and energy-related chemical manufacturing, directly or indirectly, are expected to contribute 3.9 million jobs, $533 billion (constant 2012 $) in value added to gross domestic product (GDP), and $138 billion (constant 2012 $) in government revenues by 2025.

- Growing natural gas use in the United States is not just about using more. The efficient use of natural gas and other forms of energy should continue to be a policy imperative. Cost-effectively increasing overall energy efficiency throughout the economy will require that energy policy, regulation, and consumer fuel choice be grounded in a full fuel-cycle analysis of energy requirements and costs. In many cases, increased use of natural gas to displace less efficient sources of energy may improve the overall energy efficiency of the economy.

- For many decades natural gas regulation was based on assumptions of resource scarcity. These regulations need to be re-evaluated in light of new realities. An opportunity now exists to redefine business models, regulatory policies, financial outreach and technology innovation from a position of strong supply and expectations of long-term market price stability.

- Significant regional diversity across US energy markets precludes a "one-size-fits-all" approach to energy policy, regulation, and business models. Opportunities to increase natural gas' market share will vary by region and by state.

- Bringing the benefits of natural gas to new markets will require investment by gas LDCs and their customers. In some cases, significant up front costs may be required in order to realize fuel cost savings over many years into the future. New policies and regulations may be required to assure that gas LDCs recover their prudent investment costs and that high up front costs do not deter consumers from making prudent fuel choices.

Introduction

Recent advances in the technology of natural gas extraction have opened up new opportunities across the American economy. Technologies for producing natural gas from unconventional shale and tight sandstone formations have unlocked recoverable resources sufficient to last 100 years at current rates of consumption. Even the significant increase in demand that is expected over the next two decades can be supplied from low-cost resources without requiring a significant price increase, as these technologies have also lowered the cost of natural gas. IHS CERA estimates that about 900 trillion cubic feet (Tcf) of unconventional gas resources—more than one-third of the total recoverable resource base—can be produced economically at a Henry Hub price of $4 per thousand cubic feet (Mcf) or less in constant 2012 dollars.[1] As a result, we expect natural gas prices to remain in the $4-5 per MMBtu (constant 2012 $) on an annual average over the long-term, albeit with some short-term cyclicality.[2]

What does unconventional mean?

"Unconventional" oil and natural gas is exactly the same commodity as "conventional" oil and natural gas. The word "unconventional" is typically applied to major new advances in extraction technology in the oil and natural gas industry that allow access to resources not previously technically or economically recoverable. In recent years, "unconventionals" have included oil sands, extra-heavy oil extraction technologies and deepwater drilling technologies. In this report, we focus on unconventional natural gas that is produced from low-permeability source rock using a combination of horizontal drilling, which exposes more of the subsurface to the well, and hydraulic fracturing that creates pathways that allow the oil and natural gas to flow through the dense rock into that wellbore.

The new outlook for natural gas supply and price represents a sea change from the expectations of just a few years ago when North American natural gas was viewed as a scarce resource, heading for depletion, with ever-increasing prices required to maintain production or even to attract imports. As recently as 2008, the United States was expected to become a major importer of liquefied natural gas (LNG) by 2015, at prices linked in international markets to oil.[3]

The new opportunities resulting from the unconventional natural gas revolution have taken time to assess, and initially, large-scale investments faced hesitation and even skepticism that the new resource would prove durable. Skepticism has been replaced by confidence, as reflected in the commitments being made across the US economy. Industries are responding with multi-billion dollar investments in chemical, steel, and other gas-intensive processes. Power generators are planning more investments into gas-fired power plants as they phase out some coal capacity, while also integrating new renewable capacity into the generation fleet. Transportation companies are adding compressed natural gas (CNG) and LNG automobiles, vans, and trucks to their fleets, and considering the use of LNG in locomotives, barges, and ships. Proposals to liquefy and export US natural gas are moving through the permitting process and one

[1] For purposes of this report, 1 Mcf is assumed equivalent to 1 million British thermal units (MMBtu).

[2] Note that prices are projected to be somewhat higher than the lowest cost gas resources available, as higher cost resources are always a part of a supply mix owing to practical considerations such as producers' acreage positions, adequacy of the service industry in new areas, infrastructure, market, and financial constraints.

[3] US Energy Information Administration's *Annual Energy Outlook 2008* projected gross LNG imports of 5.8 Bcf per day in 2015. *Annual Energy Outlook 2013* projects gross LNG imports of 0.5 Bcf per day in 2015.

facility is under construction. Policy makers are incorporating natural gas into efforts to move the US energy mix in a less greenhouse gas (GHG)-intensive direction.

Gas LDCs as well are in the process of re-evaluating their opportunities to serve existing customers and to expand service to new customers in ways that make sense economically and that can be developed under the umbrella of state and local regulation. Much of the prevailing natural gas regulation was developed in a time of perceived scarcity. Thus, it may be reasonable to review regulations and identify hindrances to natural gas use that may no longer be appropriate for today's and tomorrow's natural gas markets.

There has already been a positive response to the new natural gas outlook in residential and commercial markets. Conversions from oil heat to natural gas heat have accelerated, particularly in the Northeast, in response to both cost considerations and government initiatives. For example, New York City is in the midst of a large-scale conversion from fuel oil use to natural gas use. In Maine, gas LDCs are expanding their systems to deliver natural gas into sparsely populated areas serving paper mills and, with the industrial demand providing a base level of support for the infrastructure, are also connecting residential and commercial customers along the way. New pipelines and other infrastructure projects are being constructed to eliminate pipeline bottlenecks and deliver natural gas from new supply basins into growing market areas.

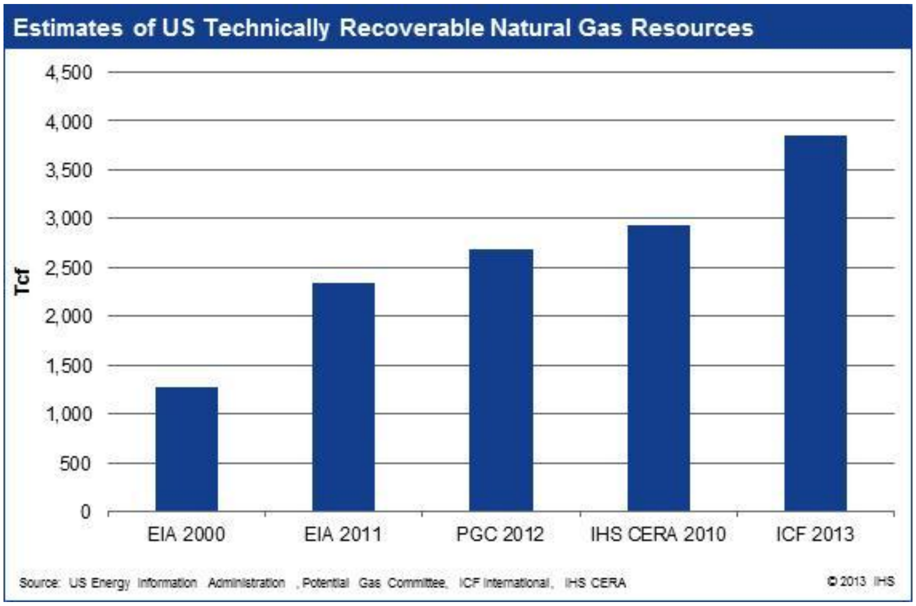
Gas LDCs face both opportunities and challenges in helping their communities take advantage of newly abundant supplies of natural gas. Natural gas provides opportunities to increase the overall efficiency of energy use, to reduce air emissions, to reduce energy costs, and to promote local economic development. Challenges include recovering the often high up front costs of investments by gas LDCs and consumers, conflicting federal, state, and local policy objectives, regulations grounded in outdated assumptions regarding natural gas supply and cost, and developing a consensus as to the new realities of the natural gas market. Specific opportunities will vary from one region to another and may require regulatory change, policy support, and financial and technological innovation to be fully realized. Similarly, challenges to achieving these goals may vary regionally and may require regulatory, policy, financial, or technological measures if they are to be overcome.

This study is intended to serve as a resource for gas LDCs, their customers, regulators, legislators and other policy makers, industry, and the general public to use in adjusting to the new realities of the natural gas market. It describes the unconventional natural gas revolution (also known as the "Shale Gale") and how it has upended long-held notions of natural gas supply and cost. It discusses the actual and potential contributions of natural gas to certain national goals such as energy efficiency, environmental benefits, economic growth and energy security. The study evaluates the potential benefits of natural gas use in the residential and commercial sectors that constitute the core markets for gas LDCs. It identifies factors that encourage as well as inhibit greater use of natural gas, with a particular emphasis on gas LDC systems and their core residential and commercial markets. It also describes how natural gas use in the power sector, the industrial sector, and even the transportation sector is evolving and how gas LDCs may be able to participate in such market growth.

The unconventional natural gas revolution

Over the past five years, it has become evident that unconventional technologies have made a vast new natural gas resource accessible to development. In recent years, estimates of the technically recoverable resource base have ranged from 2,300–3,800 Tcf, enough to supply current consumption for 88–154 years (see Figure ES.1).[4]

FIGURE ES.1



Unconventional natural gas production, driven by shale gas resources, has increased rapidly. Total shale gas production in 2000 was only 1 billion cubic feet (Bcf) per day, roughly 2% of total US lower-48 production (see Figure ES.2). By 2012, shale gas accounted for 39% of US lower-48 production and IHS CERA expects that it will account for 58% of total productive capacity by 2035. Unconventional gas from all sources (shale, tight sands, coal bed methane, and associated gas from unconventional oil plays) is expected to provide 90% of total natural gas productive capacity by 2035 (see Figure ES.3).[5]

[4] ICF resource estimate from testimony of Harry Vidas before the Subcommittee of Energy & Power of the US House of Representatives Committee on Energy and Commerce, February 5, 2013.

[5] Productive capacity is the volume of gas that could be produced without infrastructure or market constraints.

FIGURE ES.2

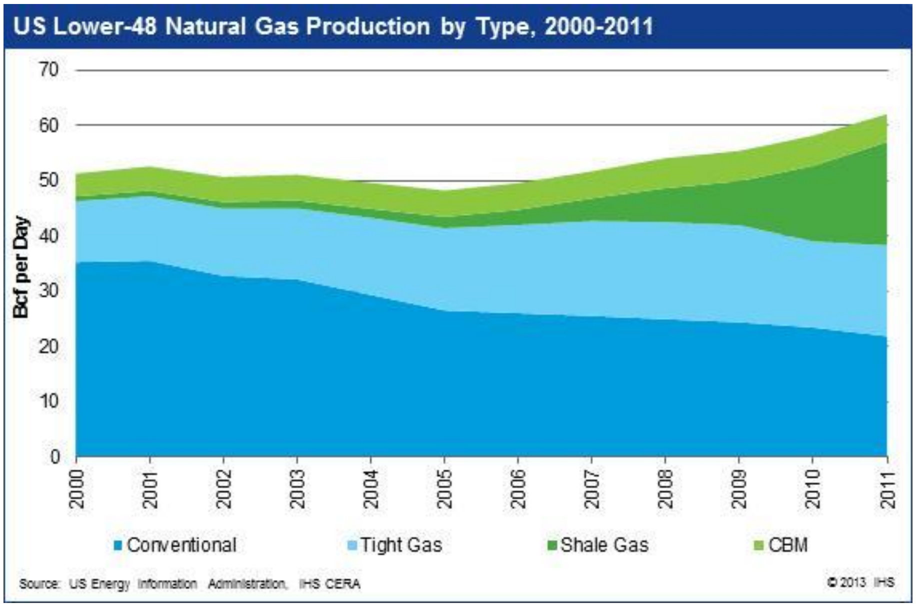
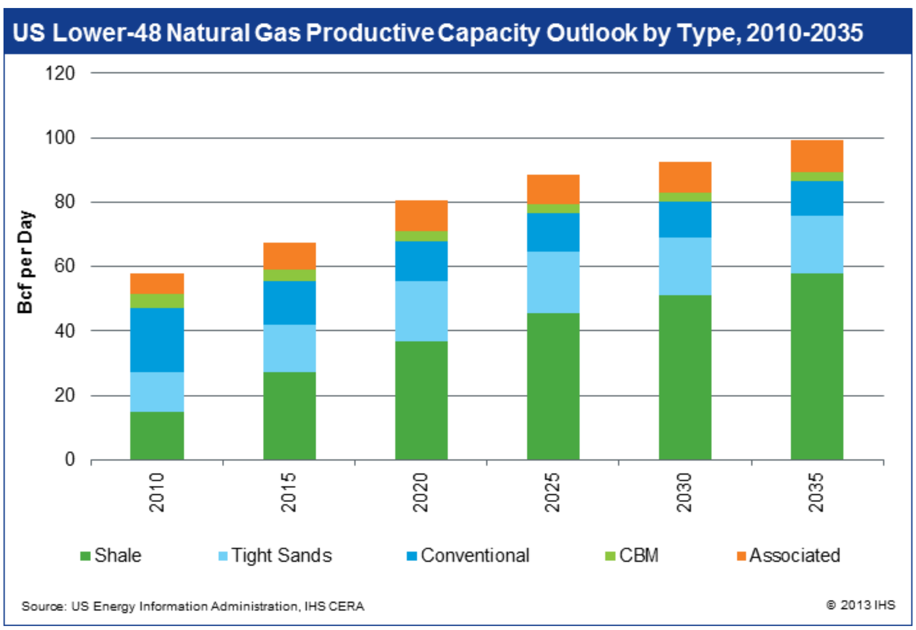


FIGURE ES.3



Lower long-term costs

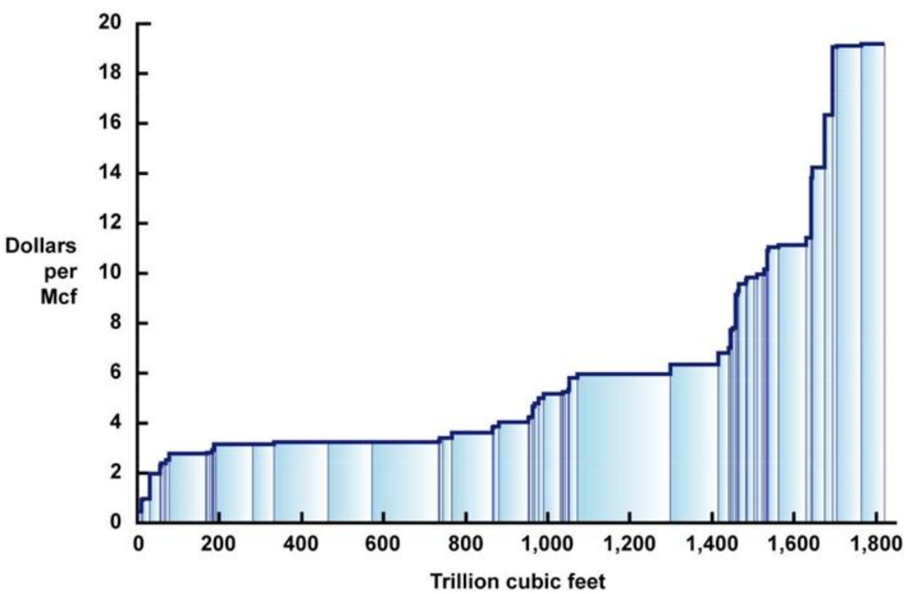
Unconventional technology is also steadily improving gas production economics. Because unconventional production techniques such as horizontal drilling and hydraulic fracturing allow greater access to the reservoir, the productivity of unconventional gas wells is much higher on average than that of conventional gas wells. As a result, although a typical unconventional gas well can cost more to drill and complete than a conventional well, the cost per unit of gas produced is usually much lower for unconventional wells than for the large majority of conventional wells—as much as 50% lower for wells drilled in 2011.

In its study *Fueling North America's Energy Future*, IHS CERA estimated that approximately 900 Tcf of the North American unconventional gas resource base from the 17 plays evaluated in that study (including two shale plays in Canada) could be produced economically if Henry Hub prices were $4 per Mcf or less (see Figure ES.4). Costs can be even lower in plays with high proportions of valuable natural gas liquids and in oil wells that produce associated gas, as revenues from the sale of liquids offset some or even all of the costs of drilling and completing the wells.

Because so much unconventional gas resource is now available at a cost in the $4 per Mcf range, the supply curve for natural gas has become highly elastic. In other words, the US natural gas resource base can now accommodate significant increases in demand without requiring a significantly higher price to elicit new supply. Other recent estimates of the gas resource base are even larger than IHS CERA's which reinforces our outlook as conservative.

FIGURE ES.4

Full Cycle Breakeven Price for 17 Unconventional Gas Plays in North America



Source: IHS CERA.
Note: Includes proved, probable, and possible resources.
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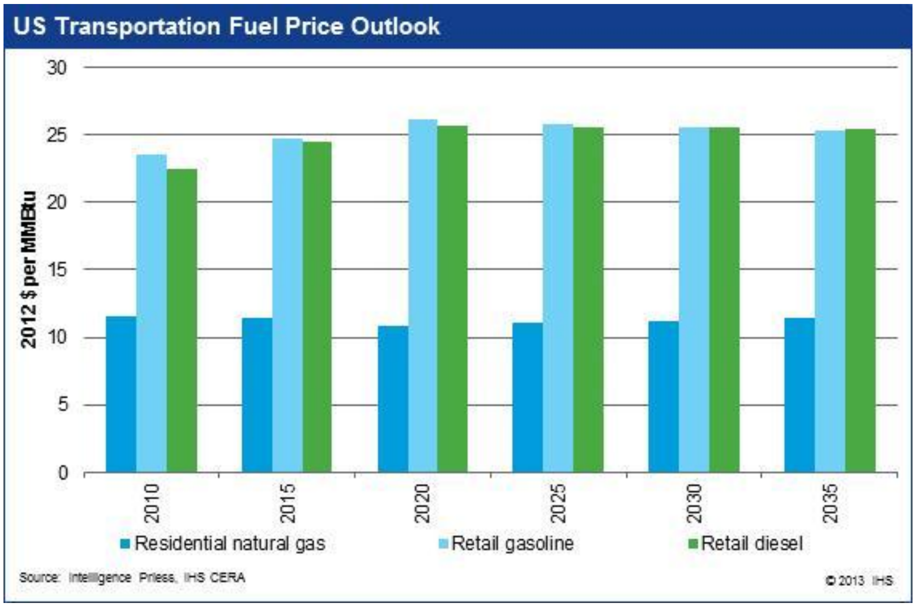
The natural gas price advantage

With a long-term elastic supply curve allowing new demand to be met for many years from supplies costing about $4 per Mcf, IHS CERA expects the Henry Hub price of natural gas to remain in the $4-5 per MMBtu range (constant 2012 $) on an annual average through 2035. (Projected prices are somewhat higher than the lowest cost resources as higher cost resources are always a part of the gas supply mix.)

In contrast, the price of crude oil is projected to remain around $90 per barrel (constant 2012 $), or almost $16 per MMBtu, over this period. This implies that oil prices, in Btu terms, will be three to four times higher than natural gas prices for decades to come.[6] This oil/gas price relationship will extend to the retail level. IHS CERA expects that residential natural gas prices (which include the cost of gas plus the costs of transmission and distribution) will remain below $11 per MMBtu (constant 2012 $) on average for 2012-2035. The projected retail costs of gasoline and diesel fuel will be approximately twice the natural gas price on a Btu-equivalent basis (see Figure ES.5). Such a sustained price differential will help to increase the attractiveness of natural gas as a transportation fuel.

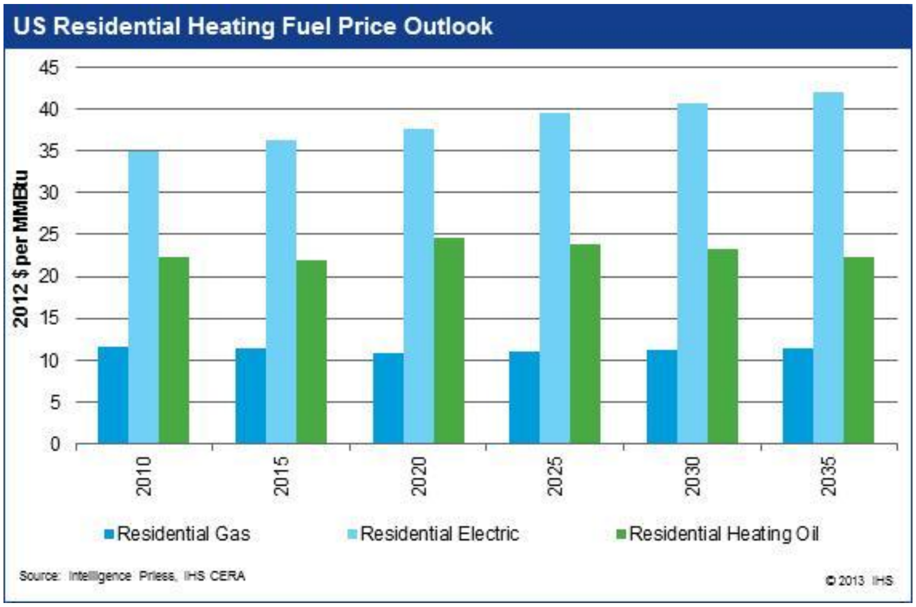
FIGURE ES.5



Similarly, delivered prices for home heating oil (a fuel chemically similar to diesel) are expected to be more than twice as high as rates for residential natural gas service, encouraging the ongoing process of replacing fuel oil with natural gas for home heating. Residential electricity rates are also expected to increase in the future, reflecting the costs of investments in generation and electric transmission/distribution, as well as policy-driven investments in pollution controls, energy efficiency and renewable power. On a Btu-equivalent basis, residential electricity rates are expected to average 3.5 times as expensive as residential natural gas rates on a national average (see Figure ES.6). Similar trends are expected for energy prices in the commercial sector.

[6] This stands in sharp contrast to the recent past. From 2000-2008, oil prices were never more than twice the natural gas price (on a Btu-equivalent basis); in 2003 the oil price was roughly equal to the natural gas price.

FIGURE ES.6



Natural gas costs and prices in perspective

With so much natural gas supply expected to be cost-effective to produce at Henry Hub prices of about $4 per MMBtu, the new outlook for natural gas is said to be one of abundance and low cost. In this context, "low cost" does not suggest that natural gas will cost less than all other fuels—the price of coal is expected to remain significantly below that of natural gas on an energy-equivalent basis.[7] Nor does it indicate that natural gas costs and prices will be lower than they have ever been--historically natural gas wellhead prices have remained below $4 per MMBtu (in constant 2012 $) except for two periods: 1981-1985 and 2000-2008. Nor does it mean that volatility has been eliminated—daily, monthly, and seasonal volatility will continue to reflect unexpected events and temporary misalignment of physical demand and supply, often caused by variations in weather.

Rather, "low cost" natural gas in the context of the unconventional natural gas revolution indicates that:

- Natural gas prices will not have to increase materially to elicit additional supplies, owing to the extensive resource base that is available at a full-cycle breakeven price of about $4 per Mcf;
- Natural gas prices will remain significantly lower than had been expected prior to the Shale Gale;
- Retail natural gas prices are expected to remain lower over the long-term, on a Btu-equivalent basis, than refined oil products or electricity.

[7] From early 2009 through mid-2013, the dispatch costs of many gas generation units have been lower than those of many coal generation units even though natural gas prices have been higher than coal prices on a Btu-equivalent basis at times; the price disadvantage has been more than offset by gas generation's efficiency (or heat rate) advantage.

Natural gas and national energy objectives: security, economic growth, environment, efficiency

US energy policy has traditionally focused on several objectives. These include price moderation, energy efficiency, cost efficiency, environmental protection, and energy security. The new outlook for natural gas cost and availability has created new possibilities for progressing toward these goals. In addition, the development and extraction of unconventional natural gas and oil is contributing jobs and revenues to the economy.

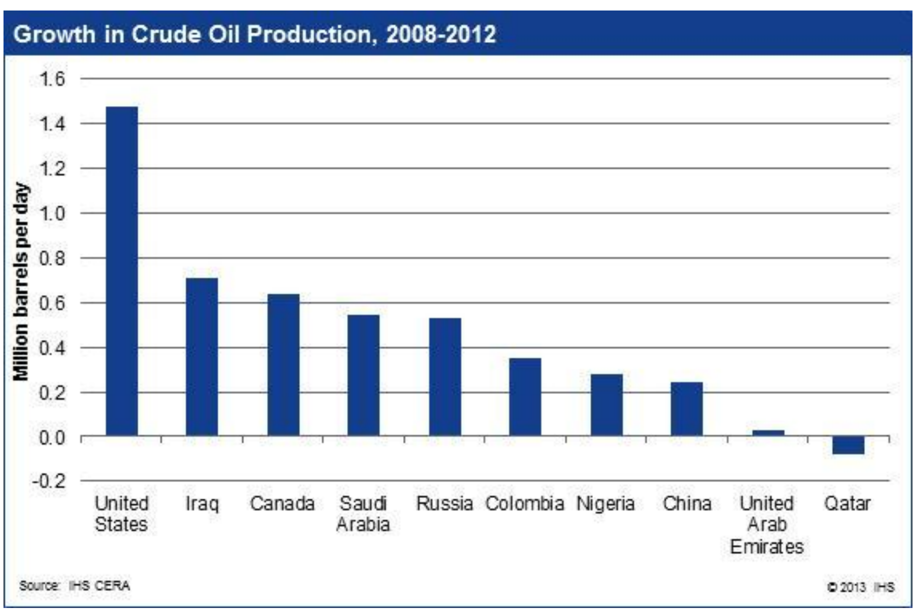
Improving energy security

The United States is essentially self-sufficient in natural gas, producing 92% of its total supply and importing the rest from Canada. Before the Shale Gale, increasing dependence on LNG imports had been envisioned. Instead, the United States is poised to become a natural gas exporter via LNG within several years.

Moreover, the transfer of unconventional natural gas technology to oil plays has unlocked a new crude oil resource base that had previously been uneconomic. Since 2008, the United States has led the world in the growth of new supplies of crude oil (see Figure ES.7). Production of unconventional "tight" oil has increased from 100,000 barrels per day in 2003 to an estimated 2 million barrels per day (mbd) in 2012. This provided a noticeable proportion of the total supply of petroleum in the United States, which was 18.5 mbd in 2012. Because of the growth in domestic production, net US oil imports have declined to only one-third of total demand, down from 60% in 2005.

By the end of this decade, tight oil production is expected to reach nearly 4.5 mbd, representing nearly two-thirds of domestic crude oil and condensate production. Such growth will continue to reduce US oil imports in the years ahead. The rapid increase in tight oil production has also led to a substantial increase in natural gas that is associated with the primary oil production.

FIGURE ES.7



Contributing to economic growth

The growth in US oil and natural gas production is fueled by capital spending on exploration and development, which exceeded $87 billion in 2012. Since the majority of the technology, tools, and know-how are home grown, an overwhelming majority of every dollar spent through this supply chain remains in the United States and supports domestic jobs. Extensive supply chains—across many states, including states that do not directly produce unconventional oil and natural gas—reach into multiple facets of the American economy.

As the production of unconventional oil and natural gas expands over the next 25 years, the industry's economic contribution will also expand. IHS CERA projects that upstream capital expenditures will average some $200 billion (nominal $) per year during 2012-2035 for a total expenditure of more than $5 trillion over this period.[8] Unconventional oil and gas activity and energy-related chemical manufacturing, directly or indirectly, were responsible also for 2.1 million jobs, nearly $284 billion in value added to GDP and more than $74 billion in government tax revenues in 2012. By 2025, these contributions are expected to grow to 3.9 million jobs, $533 billion (constant 2012 $) in value added to GDP, and $138 billion (constant 2012 $) in government revenues.

In addition to the significant industry contributions defined above, affordable and abundant natural gas has ushered in an era of substantially lower prices than they otherwise would have been without the unconventional revolution. These lower prices are currently providing a short term economic stimulus to disposable income, GDP and employment—a positive force during a period of continued economic uncertainty and slow growth. These other economic contributions are attributable to the unconventional energy revolution and include:

- Increases in real GDP ranging from 2.0% to 3.2% per year and translating into an increase in GDP of $500 - $600 billion.

- A total net trade improvement increasing steadily until a plateau of about $180 billion per year (constant 2012 $) is reached in the early 2020s, compared to a hypothetical US trade regime in which there is no unconventional oil and gas development.

- An increase in real disposable income per household of approximately $1,200 in 2012 will steadily increase to $2,000 (constant 2012 $) in 2015 and more than $3,500 (constant 2012 $) by 2025.[9]

Regarding the last point, household income increases as a result of: (1) lower costs for natural gas used for space and water heat, (2) lower costs of various consumer goods resulting from the lower cost of natural gas used in manufacturing and in electricity generation, and (3) higher wages as the manufacturing renaissance increases industrial activity.

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[8] IHS Inc., *America's New Energy Future: The Unconventional Oil and Gas Revolution and the US Economy; Volume 1: National Economic Contributions, October 2012*.

[9] IHS Inc., *America's New Energy Future: The Unconventional Oil and Gas Revolution and the US Economy; Volume 3: A Manufacturing Renaissance, September 2013.*

Environmental considerations

Two of the greatest attractions of natural gas from an environmental perspective are (1) that it results in the lowest carbon dioxide (CO_2) emissions of any fossil fuel and (2) that efficiency increases when natural gas is used directly in homes and businesses in place of electric heat and hot water.

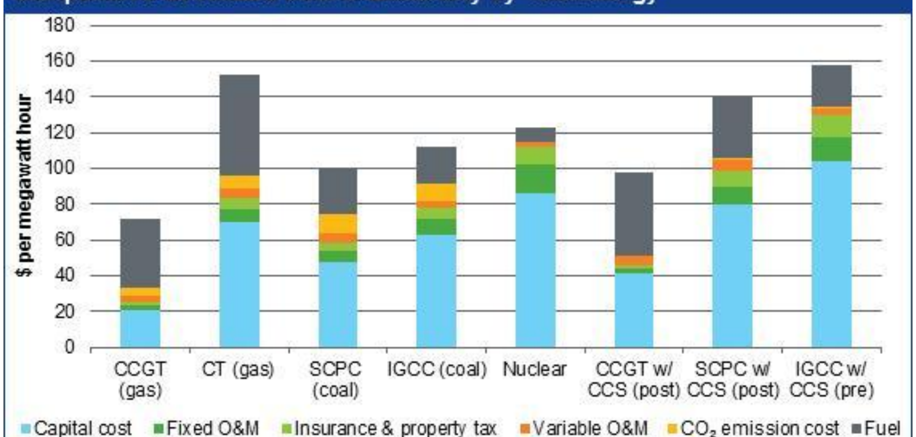
When used to generate electricity, natural gas emits as much as 50% less CO_2 than coal. In addition, natural gas use results in negligible emissions of sulfur dioxide (SO_2), nitrogen oxides (NO_x), mercury (Hg), and particulates compared with other fuels. Increasing the use of natural gas in place of other fossil fuels can therefore have both global benefits in terms of reduced GHG emissions and local benefits in terms of lower emissions of SO_2, NO_x, mercury, and particulates in the United States.

Already, substituting natural gas for coal in power generation is tempering the growth of US power sector CO_2 emissions. The decline in the spread between natural gas and coal prices that began in the spring of 2009 altered the competitive position of natural gas-fired power generators in many US markets, and caused a significant amount of coal generation to be displaced by lower-CO_2 emitting gas generation. In 2012, US power sector CO_2 emissions were the lowest that they have been since 1995, and 16% below emissions in 2005 (an often used baseline year).

Natural gas is not emissions-free. If natural gas is to be used to help manage atmospheric concentrations of GHGs, technologies must ultimately be developed to economically remove CO_2 from the natural gas combustion process. A variety of carbon capture and storage (CCS) technologies are under development for use with either coal-fired or natural gas-fired power generation, but significant challenges remain. CCS will make generation more costly, but gas with CCS is expected to be less costly than coal with CCS (see Figure ES.8).

FIGURE ES.8

Comparative Levelized Cost of Electricity by Technology



Notes: CCGT = combined-cycle gas turbine; SCPC = supercritical pulverized coal; IGCC = integrated combined-cycle; CT= combustion turbine; CCS = carbon capture and sequestration.
Does not include storage, production (PTC) or investment tax credits (ITC).
Delivered fuel prices: natural gas=$4.95/MMBtu; coal=$2.60/MMBtu for SCPC, $2.00/MMBtu for IGCC; nuclear=$0.70/MMBtu. Inflation is 2.0% and financing is 50/50 debt/equity split with 7% cost of debt and 11% after-tax cost of equity. CO_2 price =$11 metric tonne.

Source: IHS CERA

Most forms of energy development—including natural gas, oil, wind, and solar—result in land disturbances, dust, noise, vehicle traffic, and water impacts; many of which are temporary. The process of natural gas development specifically involves site preparation, drilling, well completion, production, and the construction of infrastructure to connect new gas supplies to markets; all for which best practices should be applied. Also best practices for water use and the safe disposal of wastewater are being addressed to help diminish concerns about hydraulic fracturing.

Natural gas does possess one potential disadvantage from an environmental perspective, however. Natural gas is about 95% methane; methane has about 28 times the global warming potential of CO_2 when it is emitted into the atmosphere rather than combusted.[10] Direct emissions of methane into the atmosphere—whether from upstream operations, leaks in the pipeline and distribution systems, or accidents anywhere within the natural gas system—have environmental consequences. Minimizing methane emissions from natural gas production, processing, transmission, and distribution is an important factor in realizing the climatic benefit of fuel switching from other fossils fuels to natural gas.

The precise level of methane emissions is unknown and efforts are underway to collect better data, particularly through direct measurement at well sites and other locations. As a remediation action, a US Environmental Protection Agency (EPA) regulation that takes effect on January 1, 2015 will require reduced methane emission completions on all wells drilled after that date. Such systems are already widely used throughout the United States and are mandated by several states.

A framework of regulation is emerging at the state level that seeks to mitigate safety and environmental concerns associated with well construction and completion practices. The incremental rules put into place over the past few years have not slowed growth in drilling and production, supporting the view that reasonable regulations are not likely to materially inhibit hydrocarbon supply in North America.[11]

Gas LDCs also have a role to play in reducing methane emissions. EPA data indicate that natural gas distribution activities account for about 16% of total GHG emissions from the natural gas sector. Programs designed to replace aging pipe, safety priorities, and the fundamental economics of serving customers dictate the gas LDC interest in improving this important environmental metric.

Energy efficiency and cost efficiency

Since the 1970s, increasing the efficiency of energy use has been a priority of national energy policy. Major gains have been achieved by appliance energy standards, stricter building codes and site energy efficiency programs. These programs all focus on improving energy efficiency at the point of consumption and were developed in era when natural gas was considered a scarce and expensive resource. For example, appliance energy efficiency labels report site energy efficiency (efficiency at the point of operation—electricity or gas input to the appliance versus useful energy produced by the appliance). The use of site energy efficiency is limiting in that it does not take into account energy necessary produce and deliver energy to a site. A more relevant measure is the "full fuel-cycle" efficiency or "primary energy" efficiency, which includes the energy required to produce and deliver gas or electricity to the appliance versus useful energy produced by the appliance.

Because natural gas uses the equivalent of about 8% of its energy to make the trip from wellhead to burner tip, a natural gas appliance will have a full fuel-cycle efficiency that is about 92% of its site efficiency. The loss is much greater for electricity. Although there is a wide variation across regions, on a national average in 2012 electric generation used 60% of its energy input to produce and deliver fuel to the power plant, to generate electricity, and to deliver it to end users. As a result, an electric appliance will have a full fuel-cycle efficiency that is only about 40% of its site efficiency.

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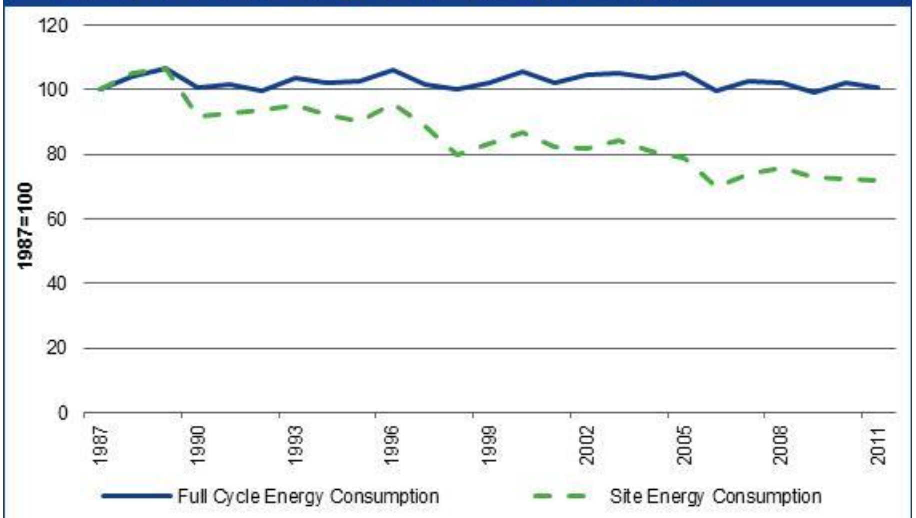
[10] The global warming potential (GWP) for a particular greenhouse gas is the ratio of heat trapped by one unit of mass of the greenhouse gas to that of one unit of mass of CO_2 over a specified time period, in this case 100 years. Methane also has a relatively short atmospheric lifetime of 12 years, meaning that its GWP is higher over shorter time frames than the 100 years typically used in climate analysis. *Fifth Assessment Report of the Intergovernmental Panel on Climate Change (IPCC)*, Geneva, Switzerland, 2013.

[11] IHS Inc., *Prudent Oil and Gas Development and the Evolution of US Regulations,* April 2013.

The residential sector has achieved significant energy efficiency gains when site energy consumption per household is considered. Site energy consumption per household was 28% lower in 2011 than it had been in 1987 (see Figure ES.9). When the losses associated with generating electricity are taken into account, however, overall primary energy consumption per household in 2011 was almost identical to its level in 1987, illustrating the importance of evaluation using full fuel-cycle energy consumption.

FIGURE ES.9

Full Fuel-cycle and Site Energy Consumption per Household

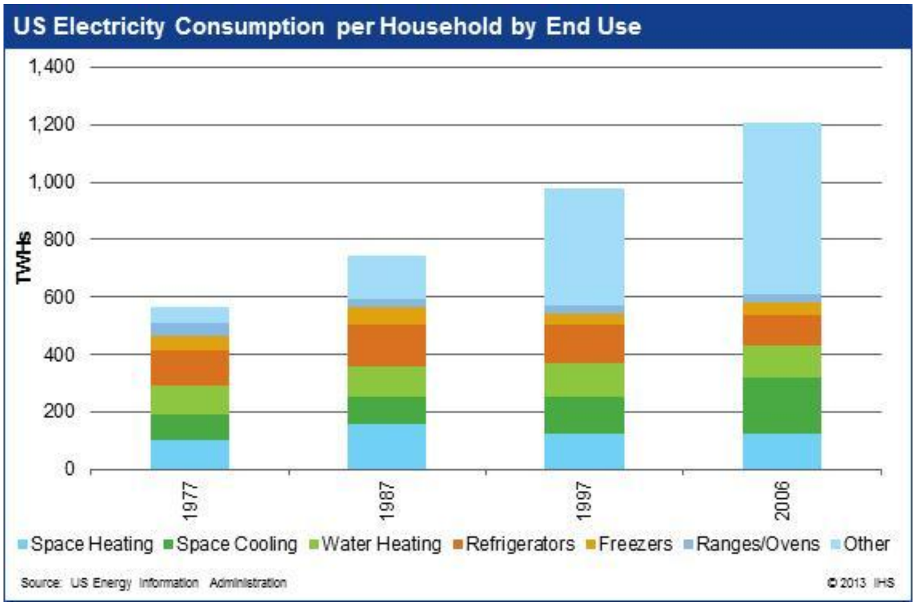


Source: US Energy Information Administration, IHS CERA © 2013 IHS

This result is due primarily to the increased share of electricity in total household fuel consumption. Although electricity consumption has declined for almost all applications that were available in 1977, owing to energy efficiency improvements for cooking, lighting, refrigeration, water heating, and space heating and cooling, total electricity consumption per household has grown significantly as other uses of electricity have been devised, such as computers, cell phones, and high-definition televisions (see Figure ES.10). EIA has remarked that "the number of [new] devices per household have offset efficiency gains in residential electricity use."[12]

[12] US Energy Information Administration, Two perspectives on household electricity use, Today in Energy, March 6, 2013, http://www.eia.gov/todayinenergy/detail.cfm?id=10251&src=email.

FIGURE ES.10



Because of the energy losses incurred in the generation of electricity it may be possible to achieve significant energy efficiency gains and GHG emissions reductions by substituting natural gas consumption for electricity consumption for uses—such as space heat, water heat, or cooking—that can be served by either energy form.

But energy efficiency does not necessarily equate to cost efficiency, which depends not only on the energy efficiency of the appliance but also on fuel costs and capital costs. With the prospect that natural gas prices will be significantly lower than electricity prices in many regions over the long term, the life-cycle cost of natural gas appliances can be lower than that of their electric counterparts. However, the up front capital and installation costs of natural gas appliances may be higher than that of electric appliances. The natural gas advantage is realized over time as lower fuel costs gradually overcome the higher initial costs, but payback periods may be longer than consumers are willing to accept. Cost-reducing technologies and financial incentives or other measures that help reduce payback times may be required if natural gas is to gain market share.

State governments and PUCs should consider adopting policies that are underpinned by full fuel-cycle energy efficiency analyses, full fuel-cycle emissions analyses, and life cycle cost analyses. Such analyses may in many instances be supportive of expanding natural gas use by existing customers and extending natural gas service to new customers.

Growth of LDC systems and natural gas markets

The US natural gas distribution system is one of the foundations of the American economy and life. It serves more than 65 million households, more than five million commercial customers, and over 190,000 industrial and power generation customers. Almost all residential and commercial gas users rely on gas LDCs for their gas purchases and/or deliveries. Perhaps surprisingly, 95% of all industrial gas customers and nearly 70% of all power generation customers also depend on gas LDCs for their gas deliveries, although in terms of volumes only about half of the gas used in the industrial sector and only about one-quarter of gas used for power generation go through a gas LDC system. Very large gas-using industrial and power facilities are often not served by gas LDCs, but instead are directly connected to wholesale pipelines.

Gas LDCs are a diverse group. There are over 1,200 gas LDCs in the United States that are investor-owned, municipally-owned or owned by co-operatives. Gas LDCs range from very small to very large in terms of number of customers, throughput and geographic area served. Climate conditions of markets served also vary significantly. Market characteristics, operating parameters, rates, and tariffs are diverse. Some LDCs own wholesale gas storage facilities and high pressure gas pipelines. This structural diversity makes it difficult to generalize about gas LDCs.

Gas LDC services, rates and facilities are regulated by 49 PUCs or by their municipal or co-operative owners. Some PUCs have appointed commissioners, while some have elected commissioners, but all are subject to political and ratepayer pressures. The policy objectives of PUCs are usually set by legislation and those policy objectives vary across states and time.

Now that unconventional gas development has eased long-standing concerns about the adequacy and cost of natural gas supplies, many of these PUCs may choose to encourage gas consumption or remove policies that discourage gas consumption within their states.

Growth from the gas LDC perspective

Gas LDCs primarily grow revenues and earnings by increasing the rate base on which they are allowed to earn a return. In addition, gas LDCs have the ability to grow earnings between rate cases by adding customers and/or throughput that exceeds the amount considered in the development of existing rates. An individual gas LDC's strategy for growth will be heavily influenced by its rate structure, tariffs, PUC policies, and state laws.

Gas LDC rates are set by regulators at a level intended to recover their costs of distribution, including a "just and reasonable" rate of return on invested capital (or rate base). Gas LDCs are not allowed to mark up the cost of the gas that they deliver through their system—and in some cases the gas itself has been purchased by the customer from a third-party.[13] Most gas LDCs have two-part rate structures that allocate costs to a fixed monthly customer charge and a volumetric or usage charge. The usage charge includes the cost of the gas and the variable costs that the gas LDC incurs in delivering the gas to the customer. The LDC's fixed costs are usually split between the customer charge and the usage charge in proportions that differ from one gas LDC to another.

Generally speaking, a gas LDC with a high proportion of its fixed costs in the usage charge will recover more of its costs if it delivers more gas to consumers and risks under-recovering its costs when deliveries decline. For such gas LDCs, increasing deliveries to existing customers—such as customers with gas water heaters who choose to replace an oil furnace with a natural gas furnace—would add to the volume of gas delivered by the gas LDC, but it would not necessarily add to the gas LDC's rate base unless new facilities were required to serve the higher load. Gas LDCs whose fixed costs and rate of return are partly allocated to the commodity charge will see higher fixed cost recovery and earnings from delivering greater volumes of gas to existing customers. These benefits are likely to be temporary if in the gas LDC's next rate proceeding throughput units for rate design purposes include the incremental volumes.

[13] According to the US Energy Information Administration, for 2012 LDCs supplied 96%, 65%, and 17% of the gas delivered to residential, commercial and industrial customers, respectively. The balance of the gas was supplied by third parties.

For gas LDCs to increase their rate base, and thereby increase profits, they must add new customers and/or expand their system into new service areas. Rate base and gas LDC earnings can also be increased if the gas LDCs have to invest in new or replacement facilities to maintain operational integrity and reliability, but such investments could increase customer rates unless the customer base also grows.

Gas LDCs whose rates are subject to decoupling adjustments are largely indifferent in the short run to the volumes delivered on their system, but they too stand to benefit from system expansions. However, in the long run, the gas LDC value proposition with the customer should be favorably impacted by increasing the number of natural gas applications used in the home or building and how those applications meet the needs of the customer.

Opportunities in core gas LDC markets

A clear opportunity exists to expand natural gas service to more residential and commercial customers who constitute the core markets for gas LDCs. The possibilities include:

- A near-term and on-going opportunity to displace heating oil in the Northeast
- An opportunity to increase gas market share in space heating and other uses, taking advantage of a growing divergence between gas and electricity prices and a greater full fuel-cycle efficiency of some gas appliances in some regions
- An opportunity to work within gas LDC service areas to use natural gas to promote economic development, attract industrial, power, or large commercial gas-using facilities to serve as anchor tenants around which a gas distribution system can be extended to smaller residential and commercial customers in the area
- Over a longer time frame, developing and improving natural gas technologies, including lower-cost high-efficiency appliances, natural gas heat pumps, small-scale generation, cogeneration applications, and fueling facilities for natural gas vehicles, whether commercial or home-based

Ideally, gas LDCs may be able to expand their networks to serve a variety of customers, balancing complementary load profiles and optimizing distribution costs across the customer base.

Growth in other sectors

The 5% of industrial gas users that were not connected to gas LDC systems used almost half of industrial gas volumes in 2011, and the 31% of power sector customers that were not served by gas LDCs accounted for nearly three-quarters of power sector gas consumption. Nevertheless, prospects exist for higher gas demand from these sectors and expansions of gas LDC systems may be required to facilitate their growth. Gas-using industrial and power facilities can also serve as anchor tenants for gas LDC system expansions and as engines for local economic development. Natural gas is also poised to increase its share of a heretofore minuscule market—transportation. Gas LDCs may play a role in building and supplying residential and commercial refueling stations.

Industrial sector

Natural gas use in the industrial sector is accelerating as many gas-intensive industries are expanding their US operations in response to the new availability of low-cost natural gas and natural gas liquids. Such expansion is particularly evident in the petrochemical industry, which is investing billions of dollars in reviving mothballed facilities, relocating plants from overseas, or expanding domestic operations. Other industries are also participating in the revival, including iron and steel. Gas LDCs can play an important role in local economic development efforts by helping to attract industries into their market areas. This would not only contribute to the local economy in terms of jobs and tax revenues from industrial expansion but could also help to optimize the development of the LDC system by spreading costs across a broader customer base to the extent that the gas LDCs participate in delivering the incremental industrial demand.

Power sector

The largest projected growth in gas demand will occur in the power sector as gas generation fills the gap left by retiring coal units and also serves new electric load. Only about 25% of the gas volumes delivered to power plants go through gas LDCs suggesting that these are small volume users. Therefore, there is the potential for gas LDCs to increase their throughput and possibly add new power sector customers. In addition, some gas LDCs may be uniquely suited to offer services to power companies, such as storage, balancing, or real-time fuel deliveries as these companies increase their use of natural gas. Rate structures may have to be modified to encourage gas LDC diversification into such services. Also new power plants might also serve as anchor tenants for expanding a gas LDC system.

Combined heat and power (CHP)

When a power generation unit is combined with a heat recovery system, it becomes a CHP plant, producing electricity and heat from a single source at the site of use. Natural gas is the fuel of choice for existing CHP plants, with 71% of capacity consuming 3.4 Bcf per day of gas.

One of the biggest advantages of CHP includes the higher electrical efficiency that comes first from the cogeneration of heat and power on site and second from the avoidance of the losses associated with the transmission and distribution of moving power from a central generating unit to an end user site. For this reason, a number of states allow CHP to be counted in their Renewable Portfolio Standards. However, high costs (equipment, installation and maintenance costs) and the need for constant thermal loads are the two most significant barriers to more widespread acceptance of medium- and small-scale CHP in the United States.

For CHP to grow, regulatory and policy changes are likely to be necessary, particularly at the state level. Some, but not all, states include gas CHP in energy efficiency and renewable portfolio standard programs. It is important for all policy makers to recognize that they may be biasing outcomes against gas-fired CHP and in favor of renewables or other technologies, perhaps in an unintended manner. Attempting to include quantification of the benefits from intangible items into the return on investment metric may also help push the odds toward an outcome that favors CHP if concepts such as independence from the grid, greenhouse gas reductions, petroleum displacement, economic development, or energy efficiency are purposely included. New business models are likely to be required that better align the interests of customers, regulators, energy suppliers, and manufacturers of CHP technology.

Transportation sector

In the transportation sector, the long-term prospects for a sustained disconnect between natural gas and oil prices (as illustrated in Figure ES.5) provide an opportunity for natural gas to progress from a niche fuel to key contributor. Mature technologies exist for natural gas use in light-duty, medium-duty, and heavy-duty vehicles—both as CNG and LNG. Although up front costs are higher for natural gas vehicles (NGVs) than for conventional vehicles, fuel savings over the life of the vehicle can pay back the higher capital costs over a period of years, depending on how much the vehicle is used. Payback periods are much shorter for heavy-duty trucks than for personal automobiles owing to the much higher vehicle miles traveled by the trucks. Natural gas-fueled personal automobiles will also have to compete not only with gasoline-fueled automobiles, but also with vehicles propelled by much more efficient electric motors.

However, NGVs have decided advantages in terms of fuel costs and tailpipe emissions compared to a gasoline-powered automobile, which has 17% higher emissions than a comparable NGV on a well-to-wheels basis.

The market potential for NGVs is quite large. All of the light-, medium-, and heavy-duty vehicles on the road today used the energy-equivalent of more than 55 Bcf per day of natural gas, primarily in the form of gasoline or diesel fuel. However, the actual market penetration of natural gas into the transportation market is very small at present. Of the 230 million light-duty vehicles (LDVs) on the road in 2012, only an estimated 100,000 were fueled with natural gas. And vehicle use of natural gas was only 0.2% of total energy consumption in the transportation sector in 2012.

A number of challenges face natural gas in penetrating the LDV market. These include high up front costs, limited refueling facilities, limited driving range, uncertain vehicle resale value, limited consumer awareness, limited manufacturer supplier base, rapidly increasing fuel efficiency standards for new vehicles, and an absence of policy support. Perhaps the greatest policy challenge holding back NGVs is the lack of a level playing field in terms of federal government incentives. These challenges can be addressed by measures such as design changes to increase driving range, cost reductions from economies of scale as more NGVs are manufactured, tax credits for NGVs comparable to those that exist for electric vehicles, technology to reduce the cost of refueling infrastructure, and coordination and education across the commercial refueling industry.

Prospects are brighter for natural gas penetration of the heavy-duty vehicle (HDV) market, where the high vehicle-miles traveled reduces payback times to three years or less given the expected lower cost of LNG fuel as compared to diesel fuel costs. Although still a challenge, fueling infrastructure is less problematic for HDVs than for other vehicle types. LNG fueling infrastructure is in its infancy with 66 stations providing LNG across the country and only 28 serving the public (as of February 2013), however these numbers are expected to double or even triple by the end of 2013 and grow thereafter. IHS CERA estimates that fewer than 250 fueling stations would be needed to blanket the US lower 48's entire interstate system at 300 mile intervals. This represents a required investment of $250-$375 million, at a cost between $1.0-1.5 million per station (minimum). By locating stations where interstates cross, this investment could be considerably lower.

IHS CERA estimates that HDV consumption of natural gas in the United States could grow to more than 4 Bcf per day by 2035.

Natural gas use in marine vessels and in railway locomotives also has potential, and pilot projects are underway in these markets.

Overcoming regulatory challenges to growth

Gas distribution systems typically are expanded only when they satisfy certain economic tests such as providing an expected net present value that is greater than zero, providing an internal rate of return that exceeds the gas LDC's cost of capital, or having a payback period that is shorter than some predetermined number of years. The application of those tests varies among jurisdictions, and often poses obstacles to system expansions that are in fact economic. A combination of gas LDC initiatives, regulatory support, and government policy could remove these obstacles, promote economic use of gas, and serve the public interest in full-cycle energy efficiency.

Gas LDCs themselves have developed strategies to encourage conversions to natural gas and system expansions. Information and outreach programs to educate consumers on the benefits of natural gas are particularly useful when energy consumers are unaware of their options. Gas LDCs can also offer loans and other financial assistance to new customers, including payment plans that stretch high up front service line and main costs over several years and loans for up front customer installation costs that can be repaid from fuel savings. They can also secure commitments for a system expansion from large anchor customers such as an industrial customer, a housing development or subdivision, a hospital, or power plant. Such commitments provide a secure base load that reduces the required contribution from other new customers. Another option is to adopt the "open season" approach used by interstate pipelines to gauge customer interest in a system expansion. If a sufficient number of commitments were gathered during the open-season period to make a system expansion economic, the gas LDC would be able to proceed with reasonable assurance of cost recovery.

Regulatory support for system expansion will also be required. PUCs can encourage these measures in several ways:

- Pre-approving system investments whose economic returns are supported by strong and credible growth projections. Pre-approval lowers the gas LDC's investment risk and makes it more likely to explore and develop system expansion opportunities.

- Endorsing economic tests that account for revenues over the useful life of the investment.

- Encouraging gas LDC financing for customer contribution in aid of construction through such devices as the free-feet mechanism.

- Permitting gas LDC or LDC-affiliate financing of conversion to gas appliances.

- Promulgating uniform standards that provide gas LDCs a clear and predictable framework for planning and evaluating potential system expansions.

The public benefits of using natural gas instead of typical alternative fuel sources may justify measures that go beyond removing economic barriers, and that actually promote the use of natural gas. Active promotion of gas at the expense of alternatives lies beyond the mandates of most PUCs, but state and local governments are entitled to make such policy choices, and can promote gas system expansion as part of an overall energy and/or economic strategy. In pursuit of such a strategy, governments should consider:

- Authorizing the PUC to allow system expansion costs to be recovered through general tariffs applied to existing as well as new customers.

- Providing explicit subsidies for expansion of gas networks to unserved areas that meet established density criteria. These subsidies could take the form of economic development grants or state-backed bonds.

- Promoting fuel conversion through information dissemination.

Implications for gas LDCs

The evolution that is now underway in natural gas markets presents a number of opportunities for gas LDCs, their customers, regulators, and policy makers. This study has identified a number of areas in which gas LDCs can work with their customers, regulators and other stakeholders to take advantage of these opportunities for mutual benefit.

Residential/commercial demand growth

Gas LDCs can grow their core residential and commercial markets by:

- Working with customers and PUCs to increase access to natural gas, help existing customers to increase their use of natural gas as desired, and extend LDC systems to serve new customers.
- Working with state governments and PUCs to change any legislation or regulatory policies that discourage the servicing of new gas load, especially if that load would improve overall energy efficiency, reduce emissions, and is economical.
- Working with PUCs, community leaders, financial institutions, and appliance manufacturers to develop mechanisms to reduce the impact of high up front costs to both the gas LDC and the consumer which can deter customers from converting to natural gas, while avoiding adverse effects on existing gas LDC customers.
- Working with PUCs and developers of multi-family buildings to reduce the initial first cost of installing natural gas space and water heating systems, while educating potential buyers or renters on the operating cost advantage of natural gas versus electric space and water heating.
- Overcoming approaches in many efficiency rulemakings which discourage inter-fuel comparisons and result in promoting inefficient technologies, backed originally by site energy efficiency analysis. PUCs will need to assure that there is a level competitive playing field for all energies, but especially between gas and electricity.

As for the future, most forecasters, including IHS CERA, expect little, if any, growth in residential natural gas demand as growth in customers (which is a function of population growth) is offset by continued improvements in energy efficiency. However, if natural gas can increase its share of residential fuel through:

- Conversions from fuel oil or electricity for both single family and multi-family households
- Improvement in the competitiveness of natural gas furnaces versus electric heat pumps
- Significant installation of home refueling units for natural gas vehicles
- Transformational breakthroughs in fuel cells or micro CHP units

then residential natural gas demand could be higher. Realizing these opportunities will be quite challenging and may require a rethinking of policies and programs by policy makers, PUCs and gas LDCs.

Promoting US energy efficiency

Gas LDCs can work with PUCs, policy makers, and other stakeholders to:

- Adopt full fuel-cycle analysis in all energy savings and energy efficiency comparisons.

- Identify new opportunities for natural gas to increase overall energy efficiency in a cost-effective manner. Given the expected growing disparity between retail natural gas prices and the retail prices of electricity and oil, it may be possible to increase overall energy efficiency by increasing natural gas use and decreasing the use of more expensive and less energy efficient sources of energy.

- Overcome approaches in many energy efficiency rulemakings which discourage inter-fuel comparisons and result in promoting inefficient technologies, backed originally by site energy efficiency analysis. PUCs will need to assure that there is a level competitive playing field for all energies, but especially between gas and electricity.

- Work with builders, local governments and other stakeholders to encourage builders to base their appliance decisions not on lowest first cost that tend not to be the most energy efficient option, but on full fuel-cycle and life cycle cost analyses.

- Explore the challenge of maintaining the cost-effectiveness, and therefore viability, of natural gas efficiency programs in the present environment of lower natural gas prices. Regulators and gas LDCs will need to review current and best practices in applying cost-effectiveness tests and potentially explore new approaches to evaluating the programs to ensure the full value of these programs are captured. Regulatory support for recognizing societal benefits of increased energy efficiency or reduced emissions will allow gas LDCs to seamlessly deliver efficiency programs to customers well into the future.

- Educate prospective converting and new customers on the economic and environmental benefits of using natural gas. Since most prospective customers are unlikely to convert until their existing furnace or water heater needs replacing, a successful program needs to be targeted at potential converting customers well before they need to replace their furnace or water heater.

- Revisit, and if necessary, update the terms of cost recovery mechanisms such as decoupling, if current mechanisms would act as an impediment to moving to a full fuel-cycle energy efficiency paradigm.

- Support efforts to set energy efficiency standards on a full fuel-cycle basis. Currently, most existing building codes and appliance standards are based on site-efficiency and ignore the losses associated with producing and delivering natural gas or electricity to the site. One exception is the EPA's EnergyStar building programs that allow comparisons of building energy use based on full fuel-cycle concepts. And in August 2013, DOE announced that it would use full fuel-cycle measures in future energy efficiency standards rulemakings.[14]

[14] *Federal Register*, Vol. 77 No. 160, Friday, August 17. 2012, page 49701.

Growth in other sectors

Gas LDCs can benefit from growth opportunities in the industrial, power, and transportation sectors.

- The fact that the majority of the number of industrial customers are served by gas LDCs presents a growth opportunity in that sector. Gas LDCs can devise strategies to maintain or increase their share of industrial gas deliveries. They can work with local communities and business development districts to attract gas-intensive industries to serve as anchor tenants and reduce the costs of system expansion. There may be opportunities to work with regulators to diversify energy efficiency offerings to industrial customers.

- The power sector has the largest potential increase in gas throughput, but gas-fired generation has a complex gas demand profile and new plants tend to connect directly to interstate pipelines. In order for LDCs to be meaningful participants in this sector, they must provide continued value to power producers – such as helping to balance short term changes in power loads, providing storage, and constructing laterals. LDCs have an opportunity to participate actively in managing real-time delivery of natural gas, given their pre-existing portfolios of gas, working with PUCs for the appropriate regulatory modifications. From a climate change perspective, replacing coal-fired power generation with gas-fired is beneficial in reducing emissions. LDCs should be important participants in this dialogue.

- Gas LDCs can be at the leading edge of the transportation sector by supporting consumer education to grow vehicle demand which will increase production of vehicles to bring down costs, supporting policies that level the playing field for all alternate fuel vehicles, providing fuel and fuel-related services that allow the buildout of refueling infrastructure, and supporting sustained R&D that will advance storage and compression technologies that reduce costs.

Combined heat and power

- For microCHP, look for ways to support research and development aimed at driving down manufacturing costs and facilitating wider distribution and installation of product.

- Support initiatives that facilitate easier, faster, and less costly ways to permit new CHP sites and drive interconnection standards towards uniformity.

- For microCHP, support common data standards, monitoring, collection and centralization from existing CHP sites for further analysis and outreach/educational programs.

- Work with regulators to expand the number of states that count CHP in Renewable or Energy Efficiency Portfolio Standards on the basis of efficiency gains.

- Work with state regulators to create equitable standby provisions, charges, and policies for CHP and help level policy playing fields for sale of power/heat/steam into wholesale and retail markets from CHP by gaining remuneration based on capacity value and voided costs of actual technologies.

Adapting regulation to support gas LDC system expansion

Traditional tests and policies relating to expanding gas distribution systems pose unnecessary and uneconomic obstacles. Gas LDCs need to take a leading role in promoting a more receptive environment for system expansion, but they cannot accomplish that task on their own. Regulatory and legislative support is also required.

- With concerns subsiding about natural gas availability and price, there is a clear justification for PUC policies that support distribution system expansion.
- State governments and PUCs should adopt policies that not only promote site energy efficiency, but also promote use of full fuel-cycle energy efficiency analysis, full fuel-cycle emissions standards and full cycle cost analysis.
- PUCs should review whether long standing rules are incompatible with current regulatory objectives and conditions in the natural gas sector, and if so, build partnerships between customers, builders, utilities, economic development agencies to work through the challenges.
- PUCs and gas LDCs should re-examine economic tests used for evaluating line expansion investments.
- PUCs and gas LDCs should review options that may ease the burden of high up front costs on prospective customers while protecting both existing customers and competing fuel suppliers.

Conclusions

The unconventional natural gas revolution has radically changed the outlook for the US natural gas market. Natural gas resources are expected to be available to meet demand for decades to come at prices much lower than were expected just a few years ago. On a Btu-equivalent basis, the wide gap between US natural gas prices and oil prices is expected to remain. And the gap between natural gas prices and electricity prices is expected to widen in many regions of the country. This presents new opportunities to reduce consumer energy costs, increase the efficiency of overall US energy use, reduce emissions of SO_2, NOx, mercury, particulates, ash, CO_2 and other GHGs, revitalize industries, increase US energy security, and promote local economic development through the increased use of natural gas. Energy policy, legislation, regulation, corporate strategy, and household decision-making will continue to adjust to the new realities, challenges, and opportunities of the natural gas market. However, obtaining potential benefits from the reinvigorated natural gas market could be jump-started by a review of PUC and gas LDC policies and practices.

Chapter I: The New Landscape for US Natural Gas Supply

In Brief

- Technologies in use for decades (primarily the combination of hydraulic fracturing and horizontal drilling) for producing natural gas have made a vast new energy resource available for development in the United States. The US natural gas resource base could satisfy current consumption needs for the rest of this century and beyond. Specifically recent estimates suggest a technically recoverable domestic gas resource base sufficient to supply current consumption (of 25 Tcf in 2012) for some 90-150 years.
- Unconventional natural gas costs much less to produce than remaining conventional natural gas on average. IHS CERA estimates that natural gas supplies should be sufficient to meet anticipated demand growth without requiring the average wellhead gas prices to exceed $5 per million British thermal units (MMBtu) (constant 2012 $) for the next 20 years.
- By contrast the real price of West Texas Intermediate (WTI) crude oil is expected to remain around $90 per barrel, or about $16 per MMBtu, making oil prices three to four times higher than natural gas prices for many years to come. That relationship creates real market opportunities for strategic use of natural gas in the United States.
- The new landscape presents opportunities to increase load growth for local natural gas distribution companies (gas LDCs). Other benefits include increased US energy efficiency and energy security, lower emissions of greenhouse gases, a revitalized US industrial base, lower consumer energy costs, and local economic development. Gas LDCs, their customers, and their regulators can work together to help realize and participate in the potential benefits of this unexpected abundance.

Recognition is growing that revolutionary change has come to the US natural gas industry. Technological development has unlocked vast amounts of previously unrecoverable or uneconomic natural gas resources at a much lower cost than was possible with conventional technologies. The implications of these changes are still being absorbed even while the revolution is spreading from natural gas plays to oil plays and from the US around the globe.

For the first time in a generation, Americans are facing abundant supplies of natural gas, a moderate long-term price outlook, and even the prospect of exporting liquefied natural gas (LNG). This outlook is radically different from just a few years ago when it was widely believed that the domestic natural gas resource base had matured, that ever higher prices would be required to elicit new supplies, and that by 2010 (if not before) the US would be importing significant quantities of LNG.

The evolution of US natural gas

The US natural gas industry has experienced many cycles and structural changes throughout its 200 year history. For most of the 20th century US natural gas was heavily regulated in all aspects of the value chain, with the growth of industry and utilities supporting continuous development and demand growth from the 1930s into the 1970s. The Natural Gas Act of 1938 gave the Federal Power Commission (FPC) authority over interstate pipeline construction, interstate natural gas transportation service, 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.

During this period, natural gas pipeline companies bought gas from producers and transported it to market areas, where they typically sold it to local gas distribution companies who then distributed and sold the gas to end users in the residential, commercial, industrial, and power sectors. Throughout the process, from wellhead to burner tip, the natural gas commodity was sold in a package with the transportation or delivery service, so that consumers purchased "delivered natural gas" from a single seller. Natural gas pipelines and gas LDCs were considered to be natural monopolies, with average costs declining as the pipeline network expanded so that no more than one company could serve a given market area efficiently. As natural monopolies, they were subject to government regulation. Gas LDCs were, and remain, regulated by state utility commissions or by their municipal or cooperative owners. Interstate natural gas pipeline companies were, and remain, regulated at the federal level.

However, the decades of wellhead price control eventually resulted in a supply shortage, especially in the 1970s.Wellhead price controls eventually misaligned costs and prices and, as a result, removed 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 1973, when production peaked at nearly 60 billion cubic feet (Bcf) per day. At that time the regulated wellhead price of natural gas was 22 cents per MMBtu, only 6 cents higher than it had been ten years before.

There followed a long decline in natural gas consumption as production (especially that dedicated to the regulated interstate marketplace) was unable to keep up with demand at the low regulated prices. Shortages developed in the interstate natural gas market, creating crises and rising political concern. During periods of peak winter demand, customers with lower-cost interruptible gas service (primarily industries and power generators) had their supplies diverted to higher-priority users such as homes, schools and hospitals. Factories and electric utilities installed dual-fuel boilers, and switched to fuel oil when gas supplies were curtailed. On occasion, factories would close temporarily for lack of fuel, and there were times when gas supplies were even insufficient to supply high priority users. In particular, during the winter of 1976-77, gas shortages forced curtailments to hospitals and schools in the Midwest and Northeast. In many states, LDCs were prohibited from signing up new customers as supplies were inadequate. Notably, such shortages did not develop in intrastate gas markets (e.g., in Texas) where gas sold into intrastate pipelines was free of price controls.

Owing largely to the outcry over the 1976-77 winter curtailments, Congress passed a package of energy legislation in 1978. The Natural Gas Policy Act of 1978 aimed at moderating and eventually phasing out price controls over a period of time. It extended price regulation to intrastate markets and established a complex system of price ceilings for many different categories of natural gas. This was seen as only a temporary solution, and most of these categories were put on a schedule for eventual decontrol.

A related piece of legislation intended to eliminate what was deemed “excess demand” for natural gas. 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 energy 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 % 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 the growing spot market were much lower, and end users sought to bypass the high-priced, contracted pipeline gas in favor of this lower-priced spot gas. The results wrought havoc with long-term contracts between natural gas pipelines and existing producers.

From 1984 to 1992 the Federal Energy Regulatory Commission (FERC)—created by the US Department of Energy Organization Act of 1977 as a successor agency to the FPC—issued a series of orders that restructured the industry. A key feature of the restructuring was the separation (termed “unbundling”) of gas commodity sales from gas transportation. Natural gas pipelines essentially became common carriers, transporting gas owned by third parties. Pipelines no longer owned the gas in their systems and, importantly, were relieved of the requirement to enter into long-term contracts with producers for gas reserves sufficient to fulfill their (now defunct) sales obligations. Large quantities of gas that had previously been contracted to pipelines were now released into the spot market, creating an immediate surplus and causing spot prices to drop even further.

At the local level, many gas LDCs eventually were similarly unbundled with sales of the gas commodity separated from the LDC’s delivery service. As a result, gas LDCs primarily sell natural gas today to residential and commercial users. Most large industrial users and power generators purchase gas from other suppliers, and where they do not have a direct connection to an interstate or intrastate pipeline, frequently purchase only distribution services from the local gas distribution company.

Natural gas prices themselves were finally deregulated at the federal level with passage of the Natural Gas Wellhead Decontrol Act of 1989, which provided for the elimination of all price ceilings on natural gas by January 1, 1993.

Free of price controls, natural gas markets began to come into balance. Prices declined in real terms from the mid-1980s until the mid-1990s and demand responded. In the second half of the 1990s natural gas was, for the first time in many decades, considered to be inexpensive and was widely available, even as the “gas bubble” was beginning to dissipate. Gas became the favorite fuel for power development—between 1990 and 2005 87% of new generation capacity was gas-fired (see Figure I.1). But by 2000 the surplus of wellhead productive capacity was gone and demand was beginning to outstrip supply once again. Markets tightened and prices began to rise sharply (see Figure I.2). For the next several years US natural gas supplies were constrained once more and concerns again mounted about the adequacy of supplies. It was expected that the nation would become increasingly dependent upon imports of LNG to fill the gap. In 2005 and again in 2008 wellhead prices averaged more than $8 per thousand cubic feet (Mcf) (constant 2012 $).

FIGURE I.1

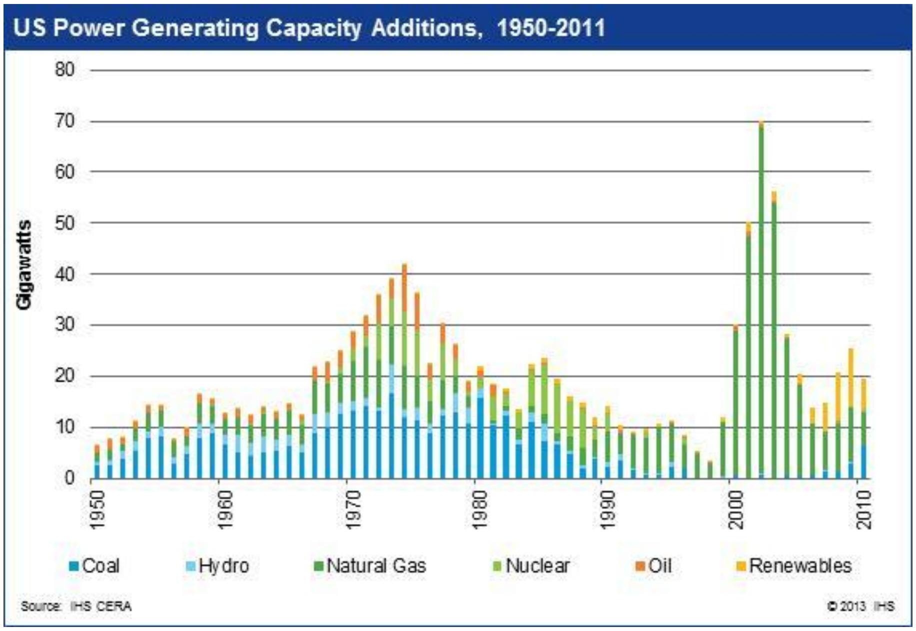
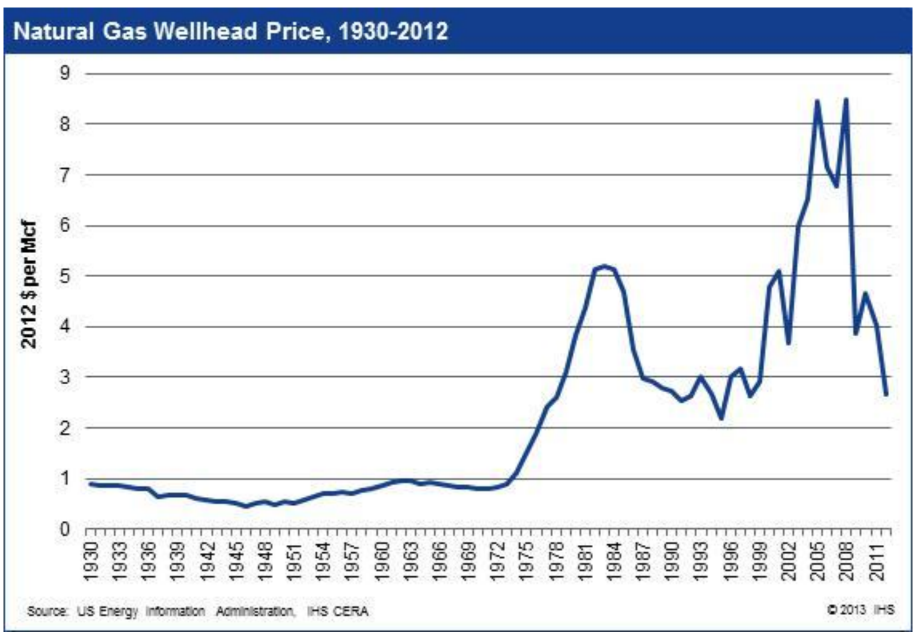
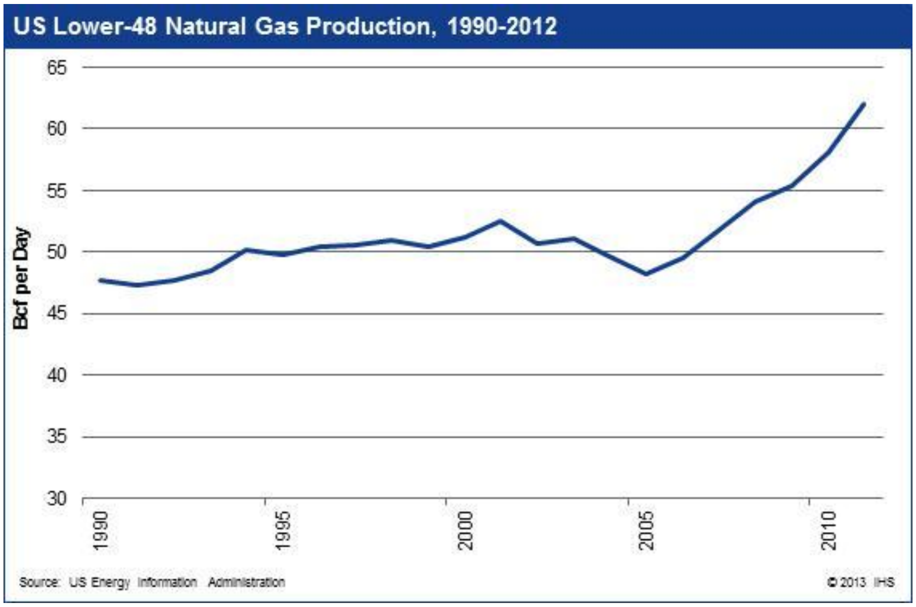


FIGURE I.2



But even as prices were peaking in mid-2008, it became apparent that the supply picture was changing. Domestic production had been increasing for 18 months. For most of the decade prior to 2007, US lower-48 natural gas production had held steady at about 50 Bcf per day. But from January 2007 to July 2008, production surged by 14%, rising from 49.7 Bcf per day to 56.1 Bcf per day (see Figure I.3). The Shale Gale had arrived.

FIGURE I.3



The unconventional natural gas revolution

Unconventional natural gas is distinguished from conventional natural gas in that it is trapped within an impermeable source rock through which it cannot readily move, which is different from the underground reservoirs that hold "conventional" natural gas and crude oil. The most prominent types of unconventional natural gas are coal bed methane (CBM), gas from tight sandstones ("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% of US lower-48 gas production.

- Tight gas (or tight sands gas) commonly refers to natural gas trapped in sandstones from which it is unable to migrate readily. Tight gas accounts for about 27 % of current US lower-48 natural gas production.

- Shale gas is trapped in impermeable shale formations and accounted for 39 % of US lower-48 production in 2012. Shale gas is expected to be the fastest growing source of supply in coming decades. In 2000 it was less than 2% of production.

What does unconventional mean?

"Unconventional" oil and natural gas is exactly the same commodity as "conventional" oil and natural gas. The word "unconventional" is typically applied to major new advances in extraction technology in the oil and natural gas industry that allow access to resources not previously technically or economically recoverable. In recent years, "unconventionals" have included oil sands, extra-heavy oil extraction technologies and deep water drilling technologies. In this report we focus on unconventional natural gas, which is produced from low permeability source rock using a combination of horizontal drilling, which exposes more of the subsurface to the well, and hydraulic fracturing, which creates pathways that allow the oil and natural gas to flow through the dense rock into that wellbore.

Unconventional natural gas is not a new supply source. In fact, the first natural gas well in the United States was drilled into a shale formation in 1821 in Fredonia, NY. The Marcellus Shale was so named in 1839 and the Haynesville Shale of North Louisiana had 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. Beginning in the early 1980s, Mitchell Energy and Development Corporation began experimenting with wells in the Barnett Shale of Texas. Over the next two decades, the company tried a variety of hydraulic fracturing techniques, eventually finding in the late 1990s a process that worked, but drilled only a few horizontal wells. After Mitchell Energy was acquired by Devon Energy Corporation in 2002, the company began to combine fracturing and horizontal drilling with great success.

Since that time, the two technologies—hydraulic fracturing and horizontal drilling—have become critical to producing 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 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 fracturing 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. Hydraulic fracturing has been used commercially in the United States since 1949 for stimulating production from conventional oil and gas wells. It has proved essential to releasing natural gas from impermeable source rock.

- 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. It first became extensively used in the 1980s in the Austin Chalk oil formation in Texas and spread through the natural gas industry in the 1990s.

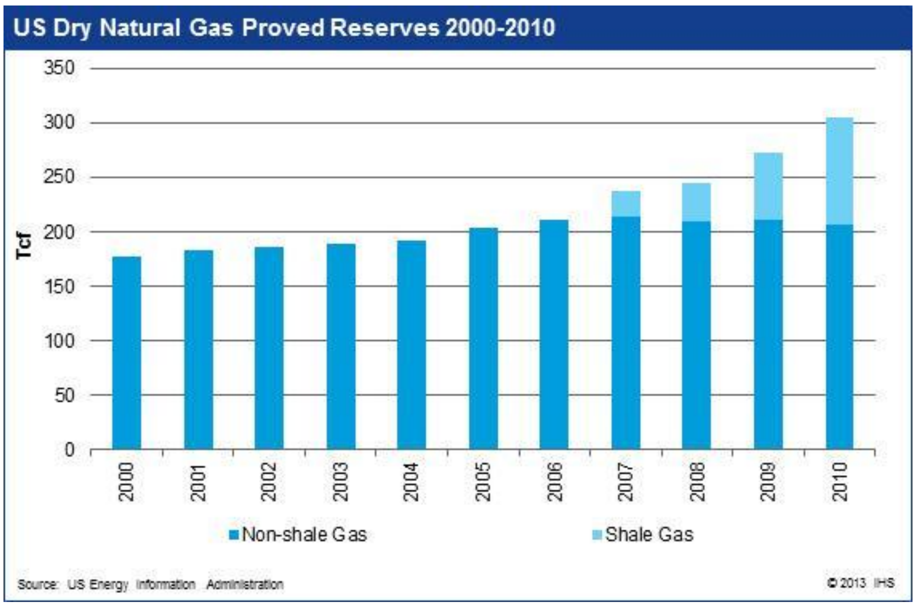
Together, these technologies now allow commercial production from formations so tight that gas had been unable to escape from them over millions of years.

Long-term supply abundance

Over the past five years it has become evident that unconventional technologies have made a vast new resource base accessible to development. One measure of the increased supply is the growth in proved reserves of dry natural gas (excluding natural gas liquids (NGLs)) as reported by the US Energy Information Administration (EIA) – from 211 trillion cubic feet (Tcf) at the end of 2006 to nearly 305 Tcf just four years later (see Figure I.4). EIA began reporting shale gas reserves separately in 2007, when they totaled 22 Tcf. Within three years this category had increased to 97 Tcf.[15]

Proved reserves are only a small part of the overall resource base. They only include "those volumes of oil and natural gas that geologic and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions" according to EIA.[16] Estimates of the total amount of gas believed to be *technically* recoverable from source rock and reservoirs—including probable, possible, and speculative reserves—vary considerably across different analytic groups.

FIGURE I.4



EIA's estimate of technically recoverable gas resources (including proved reserves and unproven resources) as of the beginning of 2011 was 2,335 Tcf (see Figure I.5).[17] The Potential Gas Committee (PGC) of the Colorado School of Mines recently estimated the total resource base to be 2,689 Tcf as of the end of 2012.[18] In 2013 ICF Resources estimated the technically recoverable US gas resource base at 3,850 Tcf.[19] IHS CERA, in its 2010 study of 15 emerging unconventional natural gas plays in the US Lower 48, estimated that the technically recoverable resources in just these 15 plays amounted to almost 1,400 Tcf. When added to EIA's proved reserves estimates and the PGC's estimates of other recoverable gas resources, the total exceeds 2,900 Tcf.[20] These estimates suggest a technically recoverable domestic gas resource base sufficient to supply current consumption (25 Tcf in 2012) for 88 – 154 years.

[15] As of this writing US Energy Information Administration has not released reserves estimates for 2011.

[16] US Energy Information Administration, *US Crude Oil, Natural Gas, and Natural Gas Liquids Proved Reserves, 2010*, August 2012, page 3.

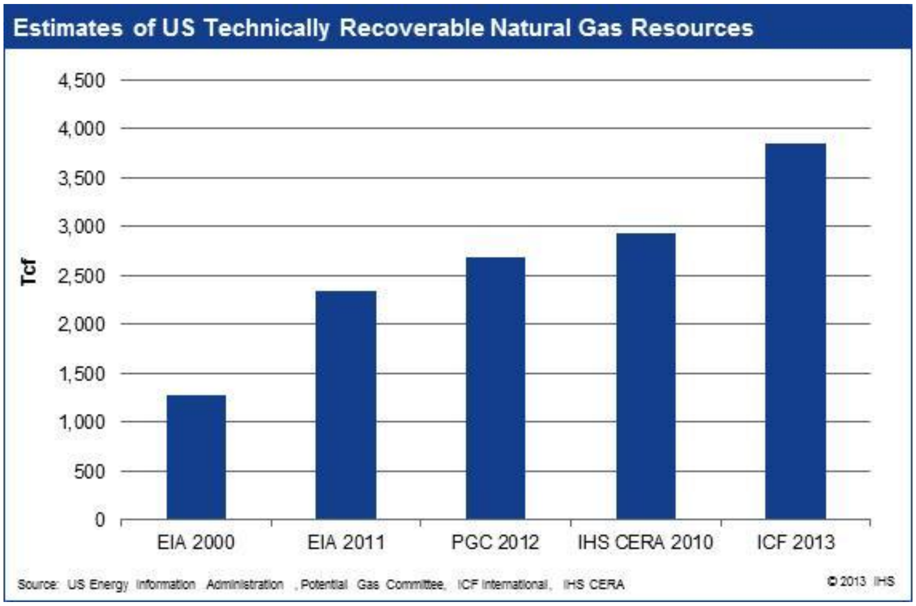
[17] US Energy Information Administration, *Assumptions to the Annual Energy Outlook 2013, Oil and Gas Supply Module*, June 2013.

[18] Potential Gas Committee, *Potential Supply of Natural Gas in the United States*, April 9, 2013.

[19] *US Oil and Gas Resources*, testimony of Harry Vidas, ICF Resources LLC, before the Subcommittee on Energy and Power of the US House of Representatives Committee on Energy and Commerce, February 5, 2013.

[20] The 2010 IHS Inc. estimate does not include resources from plays that have begun development since 2009 (such as the Utica shale) nor does it include unproved resources of associated gas in oil plays.

FIGURE I.5



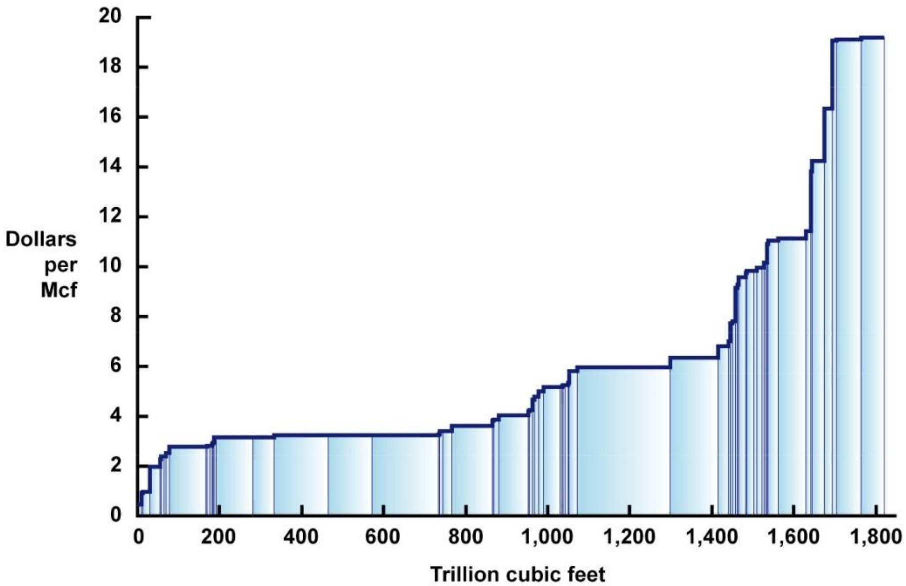
Lower long-term costs

Unconventional technology is also steadily improving gas production economics. Because unconventional production techniques allow greater access to the resource from a single well, the productivity of unconventional gas wells is very high, with typical initial production rates of 3 million cubic feet (MMcf) per day or higher. By contrast, US conventional resources, which have been exploited for decades and are thus of lower quality than they once were, have typical initial production rates of less than 1 MMcf per day. As a result, although a typical unconventional gas well can cost more to drill and complete than a conventional well, the cost per unit of gas produced is usually much lower for unconventional wells than for the large majority of conventional wells. IHS CERA estimates that the average cost of shale gas produced from wells drilled in 2011 was 40 – 50% less than the average cost of gas from conventional wells drilled that year.

In its study *Fueling North America's Energy Future*, IHS CERA estimated that approximately 900 Tcf of the North American unconventional gas resource base from the 17 plays evaluated in that study (including 2 shale plays in Canada) could be produced economically if Henry Hub prices were $4 per MMBtu or less (see Figure I.6 and the box "Full cycle unit costs and breakeven prices"). Because so much unconventional gas resource is now available at a low cost, the supply curve for natural gas has become highly elastic. In other words, the US natural gas resource base can now accommodate significant increases in demand without requiring a significantly higher price to elicit new supply.

FIGURE I.6

Full Cycle Breakeven Price for 17 Unconventional Gas Plays in North America



Source: IHS CERA.
Note: Includes proved, probable, and possible resources.
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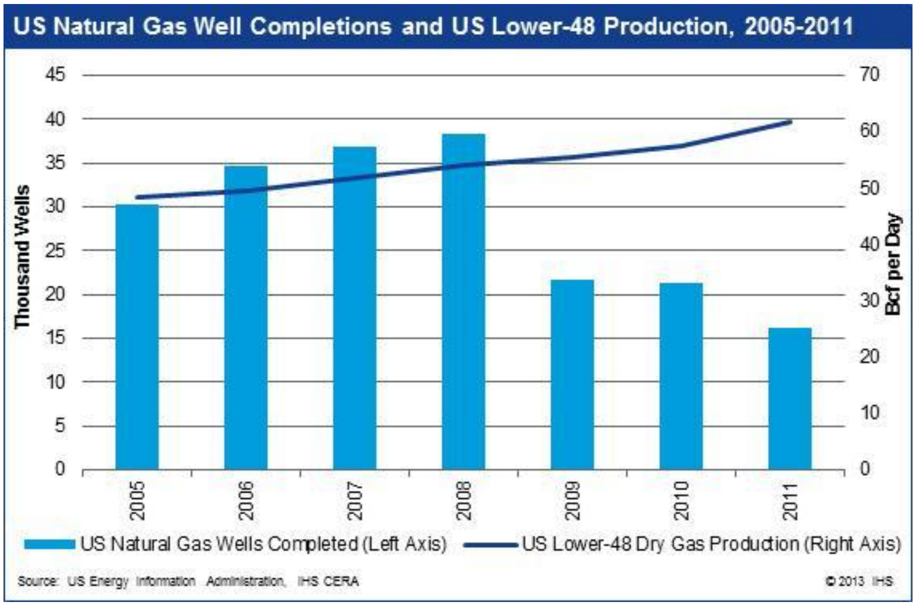
Full cycle unit costs and breakeven prices

The breakeven wellhead prices shown in Figure I.6 are calculated at the play level for the "typical" well and include leasehold costs, finding and development costs, operating expenses, royalty, taxes, and return on investment based on a weighted average cost of capital assumed to be 10%. Capital costs are success-weighted and based on equipment needed for the "typical" well. Taxes are based on tax benefits available to all producers. The economic life of the well for the purposes of these estimates is assumed to be 20 years. The average wellhead breakeven price from each play was then adjusted by the average price differential between the location of the play and Henry Hub to calculate the Henry Hub price that corresponds to the breakeven wellhead price. The full-cycle breakeven prices shown in Figure I.6 therefore represent the Henry Hub price at which the typical well in each play will recover its costs (including a 10% rate of return).

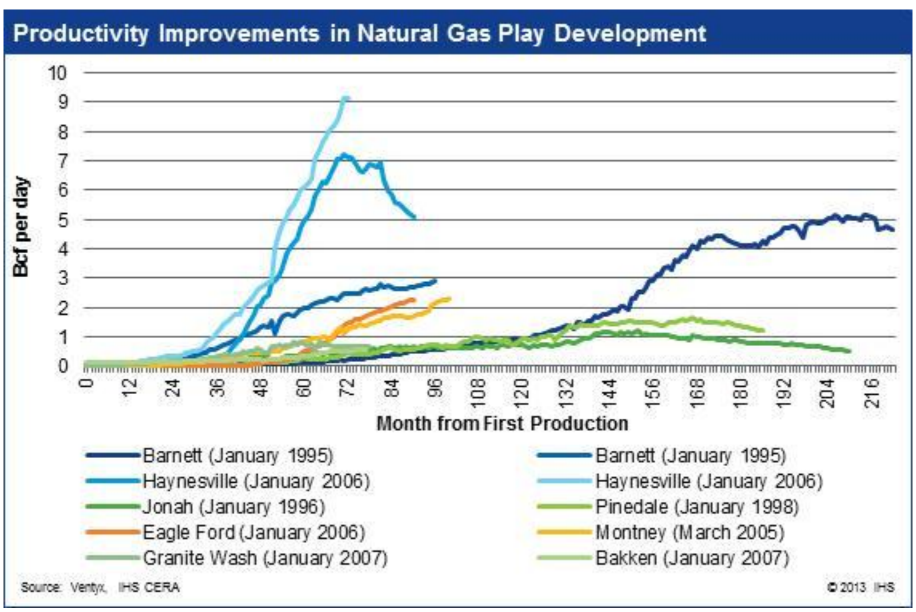
With more emphasis on unconventional gas development, with much higher well productivity, the annual well count has declined dramatically. In 2008, 32,274 natural gas wells were drilled and total production for the year was 54 Bcf per day (see Figure I.7). The next year, only 18,234 gas wells were drilled but production increased to 55.5 Bcf per day. Production has continued to grow since then, and the number of wells drilled has continued to decline. In 2011, only 14,917 gas wells were drilled, but production rose to 62 Bcf per day.

FIGURE I.7



As producers have gained experience, each well and each play has been developed more quickly and with better performance characteristics than its predecessor. For example, the Barnett shale play, where production began in 1995, took about 10 years to reach a production level of 1.5 Bcf per day and another 3 years to ramp up to 5.5 Bcf per day (see Figure I.8). The Haynesville shale play, in contrast, was producing 7 Bcf per day within four years of initial production in 2006. The Marcellus shale play has exhibited a similarly rapid ramp-up.

FIGURE I.8

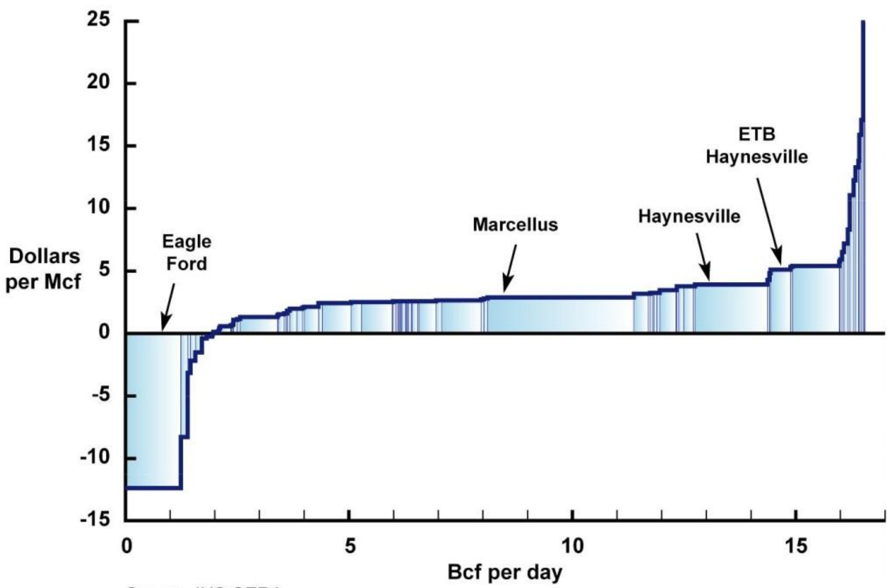


Moreover, as activity has moved toward the wetter gas plays (with high proportions of NGLs) and into oil plays (that produce "associated" gas along with crude oil), revenues from the sale of liquids can offset some, or even all, of the costs of drilling and completing the wells. For new gas supplies developed in 2012, IHS CERA has estimated that the average full cycle breakeven point was less than $2 per Mcf (see Figure I.9). The marginal cost of new gas production is higher than the average.

With such a large low-cost resource base, IHS CERA expects natural gas prices to remain in the $4-$5 per MMBtu (constant 2012 $) on an annual average over the long term, albeit with some short-term cyclicality. Note that prices are projected to be somewhat higher than the lowest cost resources as higher cost resources are always a part of the gas supply mix owing to practical considerations such as producers' acreage positions, adequacy of the service industry in new areas, and infrastructure, market, and financial constraints. And extraction costs could rise faster than overall inflation, putting upward pressure on price. On the other hand, such cost pressures are likely to be at least partly offset by the discovery and development of new plays, by cost-reducing technological innovation, and by the revenues from co-products such as NGLs.

FIGURE I.9

Full Cycle Breakeven Price of New Gas Supplies in 2012



Source: IHS CERA.
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Production growth

Unconventional gas production, driven by shale gas, has increased rapidly in the past few years. Total shale gas production in 2000 was only 1 Bcf per day, roughly 2% of total US lower-48 production. By 2010 it had grown to more than 15 Bcf per day, 27% of total production, and by 2012 shale gas accounted for approximately 39% of total US lower-48 production (see Figure I.10).

IHS CERA expects this growth to continue. By 2035, US lower-48 productive capacity is projected to grow to 99 Bcf per day of which 79% will come from unconventional gas (see Figure I.11). Another 10% will be associated gas from oil plays that are now being developed using the same unconventional technologies that unlocked the unconventional gas resource.

FIGURE I.10

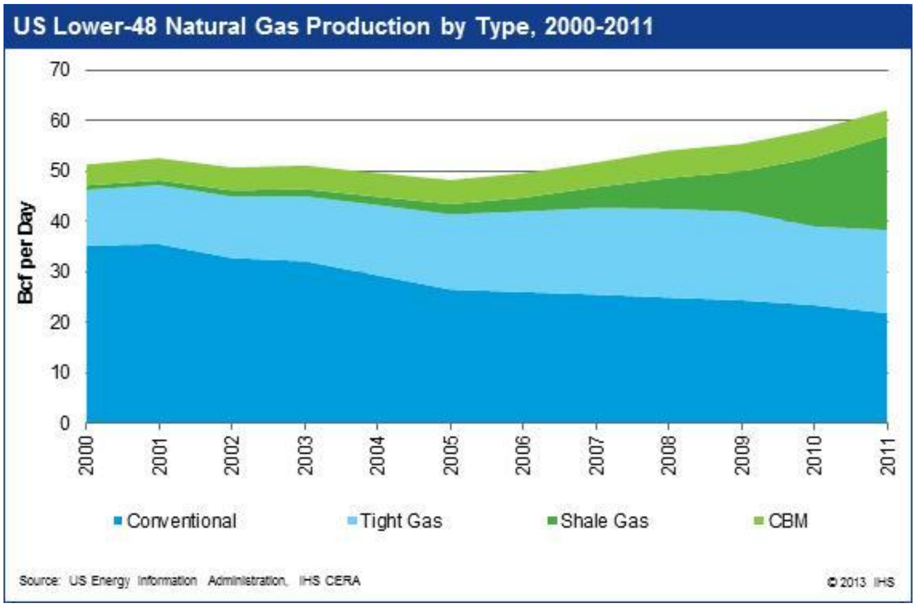
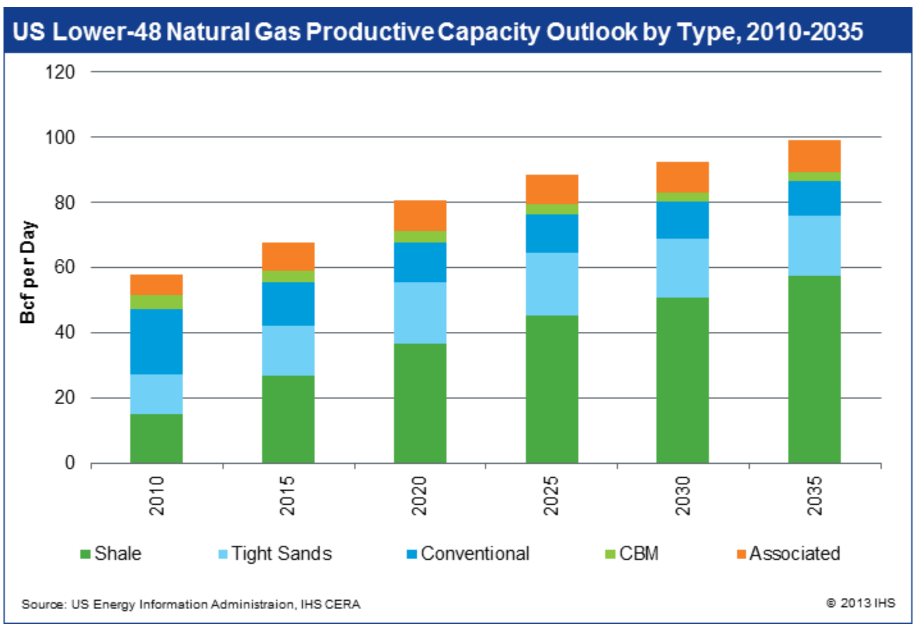


FIGURE I.11



What is different this time?

Assurances of long-term unconventional gas availability at low cost have been met with skepticism from some who remember the gas bubble of the 1980s and 1990s and the strong run-up in prices of 2005 and 2008. But the number of "shale skeptics" is diminishing with a broader understanding of the revolutionary nature of unconventional oil and gas technology. Horizontal drilling allows a single well to access much more of the hydrocarbon-bearing formation than is possible with a vertical well. Hydraulic fracturing releases much more of the hydrocarbon resource than would flow naturally into a wellbore from a low-permeability source rock. As a result, as discussed above, a single unconventional well produces much greater volumes of gas than a conventional well and costs per unit of gas produced are generally much lower for unconventional gas than for conventional gas.

As for the extent of the resource base, resource estimates are now based on actual results from known plays—well site inventories, production type curves, etc. They no longer rely heavily on estimates of "yet-to-find" resources. The location and areal extent of hydrocarbon-bearing shale formations are well known. Because operators can be proactive in developing unconventional formations—drilling horizontally through the source rock and creating artificial fractures to release the hydrocarbons instead of trying to locate a pre-existing underground pool of conventional oil or gas—much of the exploratory risk associated with conventional technologies has been eliminated.

Unlike the "gas bubble" of two decades ago, which represented a lengthy but temporary reaction to industry deregulation and restructuring, today's supply abundance is the result of a technological advance that has greatly increased the recovery factors for known deposits of natural gas. The "gas bubble" was essentially a (de)regulatory phenomenon whereas the Shale Gale is a technological revolution.

Other potential sources of natural gas supply

The resource estimates for conventional and unconventional natural gas discussed here do not include other categories of natural gas resources such as biogas, which already contributes to supply; or methane hydrates, where recent technological advances have advanced the likely timeline of commercialization. Less likely technologies that reverse the usual order of things—producing natural gas from electricity—have also been investigated.

Biogas

Biogas is produced from the decay or digestion of organic matter and is considered a renewable resource. The organic matter can be plant or animal waste, such as that found in landfill, agricultural or forestry waste, sewage, or energy crops, including possibly algae.

Two main technologies are used to convert the waste into gas: (1) anaerobic digestion, best suited to producing renewable gas from wet wastes, and (2) gasification, better suited to dry wastes or energy crops. Anaerobic digesters are already in widespread use throughout Europe. Gasification of biomass is not yet fully commercialized, but a major rollout of this technology would significantly extend the potential for biogas and the range of feedstocks that could be used in the future.

The **biogas** produced by anaerobic digestion is a mixture of methane and carbon dioxide (CO_2) with small amounts of hydrogen sulfide, water, and siloxanes. Methane content from sewage farms and anaerobic digesters varies by source but is typically in the range of 55% to 75% by volume, most of the rest being CO_2. Most biogas is used to generate electricity, preferably on site where the biogas is produced. Biogas may also be used on site in combined heat and power (CHP) applications at farms, landfills, sewage treatment plants, or other facilities. EIA reports that about 0.2 Bcf per day of biomass waste was used to produce electricity in 2011.[21] The solid by-product of anaerobic digestion, digestate, is about 90% of the original feed volume and can be used as a soil conditioner.

Biogas can also be upgraded to produce **biomethane** of high enough quality to inject into the existing gas grid. This requires separation of the CO_2 using physical absorption, chemical absorption, cryogenic separation, membrane separation, or pressure swing adsorption processes. Processing leaves a gas stream with greater than 97% methane content, which can be injected into the existing gas grid. The advantage of biomethane is that it has a higher calorific value than biogas and can be used more flexibly because it is virtually indistinguishable from natural gas. The blending of biomethane with natural gas in the grid can

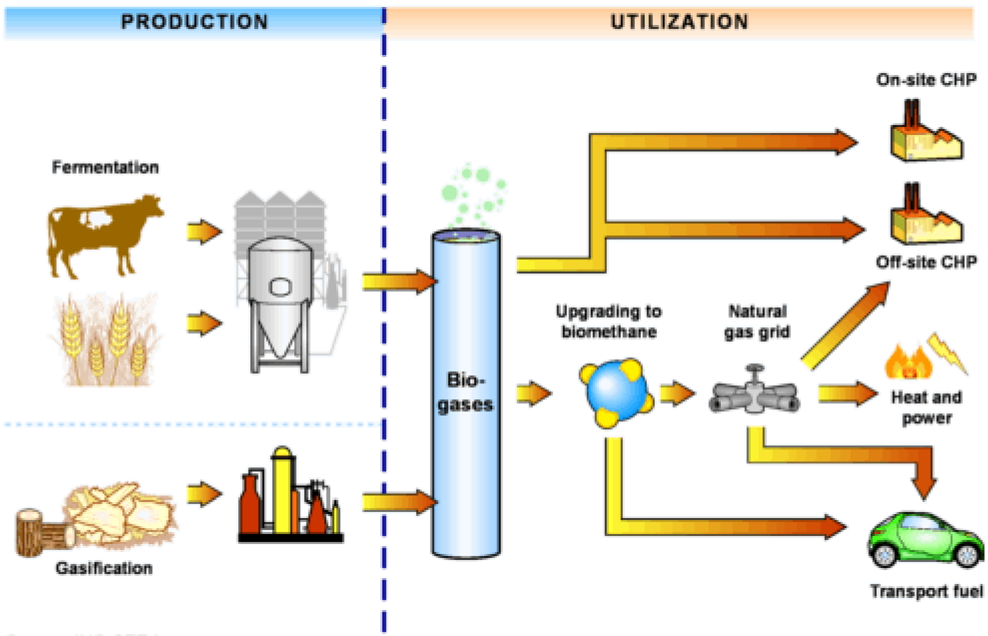
[21] US Energy Information Administration, *Annual Energy Review 2011*, September 2012.

reduce the average CO_2 footprint from combustion of the mingled product. Biomethane can also be used as a biofuel for natural gas vehicles. The main disadvantage is that the upgrading process increases the cost significantly and reduces the energy efficiency.[22]

Figure I.12 is a schematic diagram for the production and use of biogas and biomethane.

FIGURE I.12

Biogas: A Variety of Potential Sources and Uses



Source: IHS CERA.
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Methane hydrates

Methane hydrates (MH) consist of methane molecules contained within a cage of ice crystals. There is no chemical bond between the methane and the ice, and the methane is released when the ice melts. According to Dr. William Dillon of the US Geological Survey (USGS):

> *Methane trapped in marine sediments as a hydrate represents such an immense carbon reservoir that it must be considered a dominant factor in estimating unconventional energy resources; the role of methane as a 'greenhouse' gas also must be carefully assessed.*[23]

Methane hydrates are found in the outer continental shelves of countries around the world and on land in polar regions. The global resource base of MH is uncertain, with estimates ranging from 100,000 to 1 million Tcf.[24] Better estimates are available for specific areas in the United States, Canada and Japan. The

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[22] Further information on biogas and biomethane from the European perspective can be found in the IHS Inc. Private Report *New Gas for Old Grids: Biogas and biomethane*, February 2013.

[23] USGS Fact Sheet, *Gas (Methane) Hydrates – A New Frontier*, 9 January 2013, http://pubs.usgs.gov/fs/gas-ydrates/.

[24] National Energy Technology Laboratory, *Energy Resource Potential of Methane Hydrate*, http://www.netl.doe.gov/technologies/oil-gas/publications/Hydrates/2011Reports/MH_Primer2011.pdf .

US Minerals Management Service estimated in 2008 that MH in place in the Gulf of Mexico ranges from 11,000 – 34,000 Tcf. A USGS evaluation of Alaska's North Slope estimated that 85 Tcf of MH are technically recoverable using conventional technologies. Additional MH are known to exist offshore North and South Carolina, although these deposits are highly dispersed and unrecoverable with today's technology.

Clearly MH represent an enormous potential global gas resource, but development is still years away and has conflicting environmental implications. On the one hand, melting of the hydrates' ice cage can release methane into the atmosphere, accelerating global warming. On the other hand, hydrates may present an opportunity for carbon sequestration. One production technique under investigation would extract the methane molecule from its ice encasement by injecting CO_2, converting the methane hydrate into a CO_2 hydrate, thereby sequestering the CO_2 and capturing the methane for the natural gas market—a fairly complex process to be conducted under extreme conditions.

Nevertheless in the past 12 months two separate breakthroughs related to MH have been reported. On 2 May 2012, then-US Secretary of Energy Steven Chu announced a successful test of methane extraction at the North Slope of Alaska, where a steady flow of natural gas was produced from MH deposits. This test was performed by the US Department of Energy (DOE) in partnership with ConocoPhillips and the Japan Oil, Gas and Metals National Corporation (JOGMEC) and used technology developed collaboratively by the University of Bergen, Norway, and ConocoPhillips. In its field trial the team injected a mixture of nitrogen and CO_2 and succeeded in releasing methane from MH deposits. Two details about this trial are notable: the hydrates were produced from permafrost, and the technological process involved molecular displacement.

More recently, on 12 March 2013, JOGMEC announced that it had been able to produce a sustained, controlled flow of methane from seabed MH deposits offshore Japan. That test built upon earlier tests in 2002, which used heat, and in 2008, which used pressure reduction. The JOGMEC test produced methane flow using a depressurization technique, whereby pressure is reduced close to the MH source, allowing the release of methane. In this case the hydrate source was deep water and the technology was depressurization. Japan's Ministry of Economy, Trade, and Industry (METI) estimates that Japan has 38.8 Tcf of offshore MH resources in place and expects that MH production can be fully commercialized in Japan by 2028.

There is already much speculation about whether hydrates could be the "next shale gas." There are similarities in that the recent technological breakthroughs in MH do not involve the use of new technology or equipment; off-the-shelf tools and technologies were employed in the MH flow tests. Similarly, it was an innovative combination of existing technologies—hydraulic fracturing and horizontal drilling—about a decade ago that led to the breakthrough of shale gas. But there are differences as well. Because it involves an offshore technology at significant ocean depths, or a frontier technology under polar permafrost, a much smaller subset of companies will have the appetite to specialize and operate in MH than was the case with unconventional natural gas. Compared with the onshore unconventional revolution that recently led to such a dramatic, rapid rise in natural gas production, a similar pace and scale of production growth from MH is unlikely.[25]

[25] Further information on recent advances in MH development can be found in the IHS Inc. Private Report *Methane Hydrates Breakthrough: The next game changer or a major step on a longer road?* May 2013.

Power-to-gas

An intriguing possibility for additional natural gas supply does not involve the geological gas resource base at all. Rather, it involves technologies for producing natural gas from electricity. With the ramp up of intermittent renewable power technologies, there will be more need for energy storage and/or additional energy transmission. Power-to-gas is a means of storing this energy by converting it to hydrogen by electrolysis of water, or to methane in an additional step, and transporting the resulting gas using the existing natural gas grid. This could avoid planning difficulties often associated with power transmission. In the future, power-to-gas could also offer some synergies with carbon capture and storage.

The costs of power-to-gas are high because utilization of the conversion plant is low, since much of the excess wind energy is generated during only a few hours. The round trip efficiency of conversion of wind energy to methane and back to power in a combined cycle gas turbine is low. It is cheaper and more efficient to convert the excess power to hydrogen than to methane, and this could be phased in gradually up to the technical limits of the grid, which may not be reached for some time.

Despite the high cost, power-to-gas could still be in the range of cost of other storage options, and might eventually become commercially feasible.

New regional dynamics

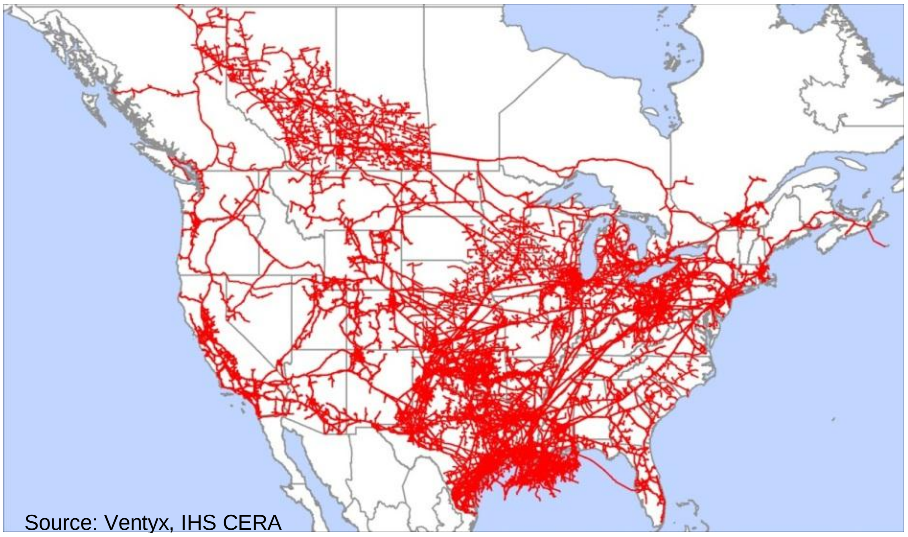
The Shale Gale has completely changed the flow patterns throughout the interstate pipeline grid (shown in Figure I.13). Whereas at one time flows from the Gulf of Mexico through the vicinity of the Henry Hub had been the marginal cost source constituting approximately 30% of US lower-48 production, they now constitute less than 5% of supply. Unconventional natural gas resources now provide two-thirds of production and are scattered throughout the pipeline network. The Marcellus alone provides more than 10% of US production and has displaced virtually all of Canadian flows into the Northeast and most of the long haul flows from the Gulf.

While this has created excess capacity from the traditional supply regions, it has also created constraints and required incremental infrastructure construction to connect and distribute this supply across the existing pipeline capacity feeding downstream markets. In general the pipeline grid has excess capacity throughout the center of the continent and has delivery constraints to the coasts, especially in the US Northwest, Northeast, and Southeast. Power generation is expected to be the major growth market for natural gas going forward and will require significant natural gas infrastructure additions, particularly in the Southeast.

Nevertheless, the growth of new supply areas around the country has already had the effect of diminishing regional price differences (see Figure I.14). Except for New England, where infrastructure limitations continue to restrict flows into the region, regional prices have converged to a small band around the Henry Hub price.

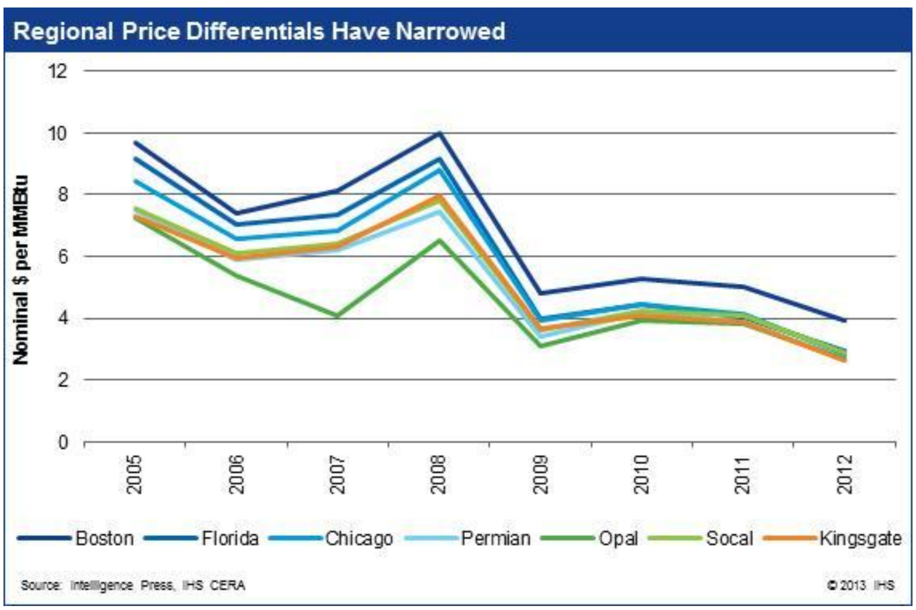
FIGURE I.13

North American Pipeline Network



Source: Ventyx, IHS CERA

FIGURE I.14



The natural gas price advantage

As discussed above, the extent and low cost of the North American natural gas resource base is such that a significant expansion in demand can be accommodated without requiring a large price increase to elicit new supplies. IHS CERA expects the Henry Hub price of natural gas to remain in the $4-5 per MMBtu range (constant 2012 $) on an annual average through 2035. In contrast, the price of crude oil is expected to remain around $90 per barrel (constant 2012 $), or about $16 per MMBtu, over this period (see Figure I.15). This implies that oil prices, in British thermal unit (Btu) terms, will be three to four times higher than natural gas prices for many years to come. This stands in sharp contrast to the recent past. From

2000-2008 oil prices were never more than twice the natural gas price (on a Btu-equivalent basis) and in 2003 the oil price was roughly equal to the natural gas price (see Figure I.16).

FIGURE I.15

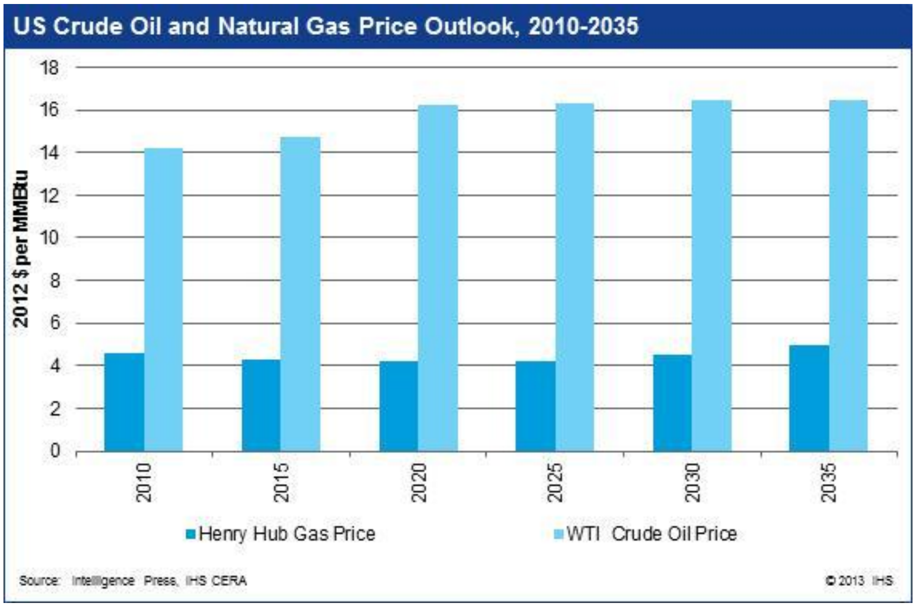
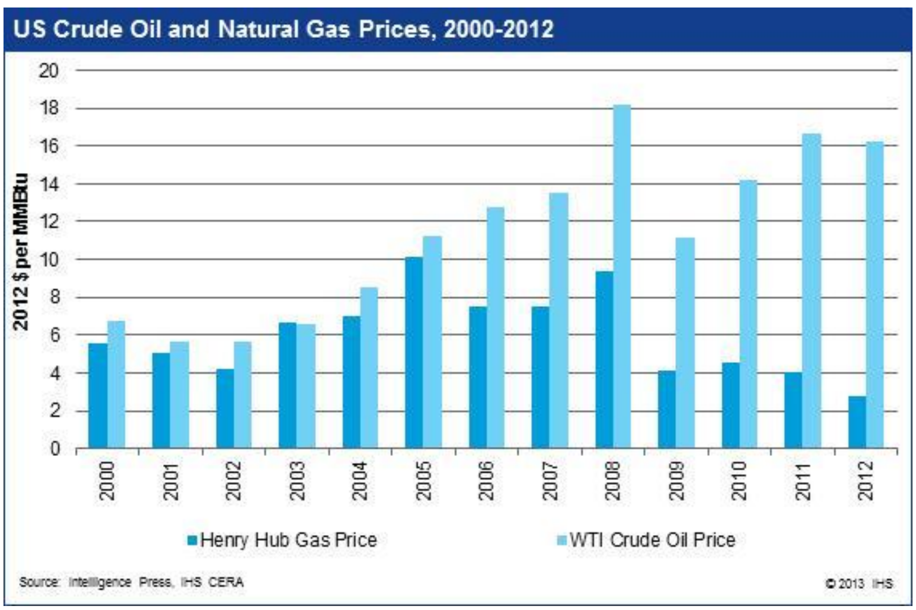
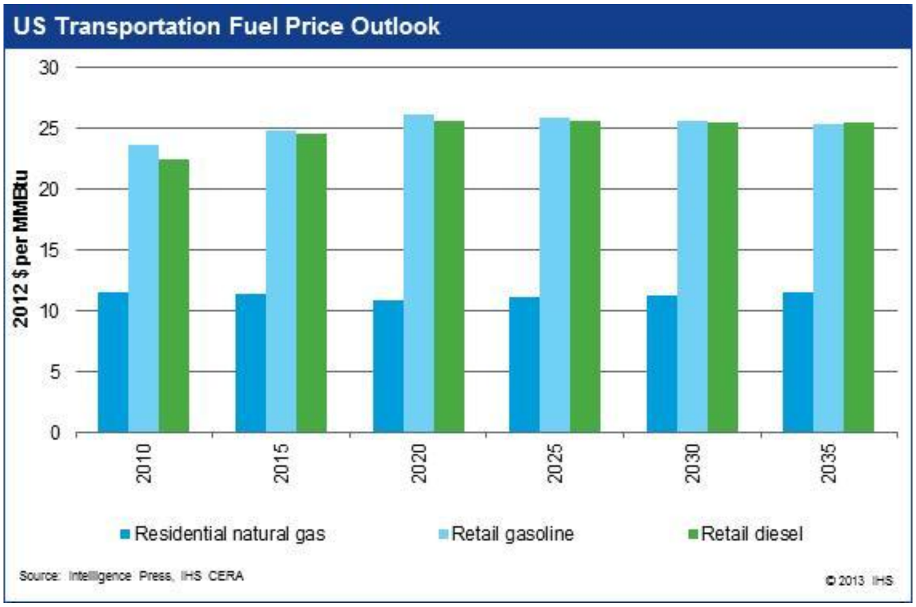


FIGURE I.16



This oil/gas price relationship will extend to the retail level. IHS CERA expects that residential natural gas prices (which include the cost of gas plus the costs of transmission and distribution) will remain below $11 per MMBtu (constant 2012 $) on average for 2012-2035. The projected retail costs of gasoline and diesel fuel will be approximately twice the natural gas price, on a Btu-equivalent basis (see Figure I.17). Such a sustained price differential will help to increase the attractiveness of natural gas as a transportation fuel as discussed further in this report.

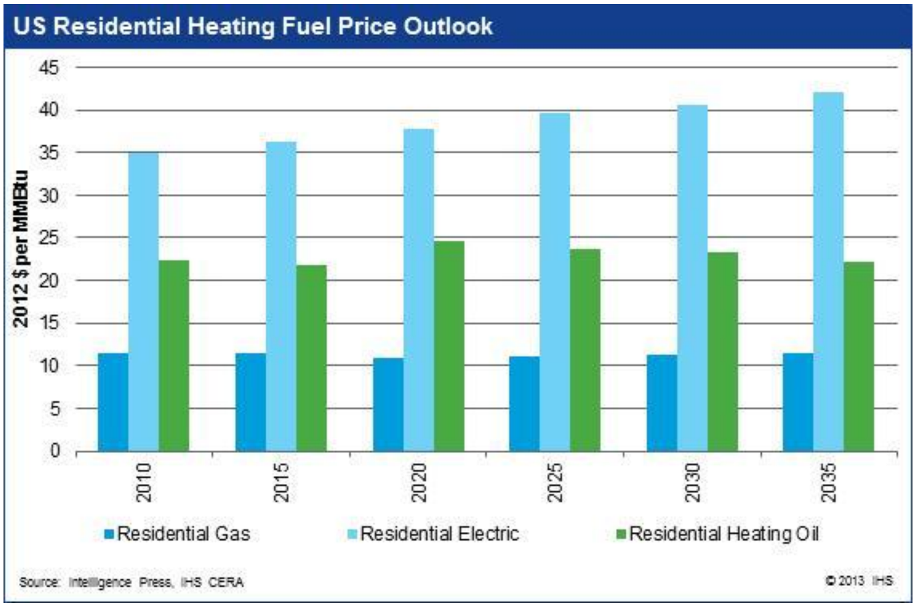
FIGURE I.17



For residential uses, natural gas will also enjoy a significant price advantage (see Figure I.18). Home heating oil prices are expected to be more than twice the price of natural gas, encouraging the on-going process of replacing fuel oil with natural gas in homes. Residential electricity rates are also expected to increase in the future, reflecting the costs of traditional investments in generation, transmission and distribution to serve growing demand and to maintain systems, as well as policy-driven investments in pollution controls, energy efficiency and renewable power. On a Btu-equivalent basis, IHS CERA expects residential electricity rates to average 3.5 times as high as residential natural gas rates on a national average (comparisons will vary regionally).

Persistently low natural gas prices relative to prices for other fuels will encourage new natural gas demand in all sectors. IHS CERA expects that residential and commercial customers will increase their natural gas consumption by adding new gas appliances and that new consumers who do not have access to natural gas at present will want to connect to the local distribution system. Industrial use of natural gas is expected to expand, particularly in those gas-intensive industries whose output is expanding, such as petrochemicals and primary metals. In the power sector, natural gas generation is already displacing coal-fired generation and supplementing renewables. IHS CERA expects this sector to show the greatest increase in natural gas demand. Natural gas has been slower to penetrate the transportation sector, but the persistent spread between natural gas and gasoline/diesel prices will encourage the use of natural gas in vehicles.

FIGURE I.18



Natural gas costs and prices in perspective

With so much natural gas supply expected to be cost-effective to produce with Henry Hub prices around $4 per MMBtu, the new outlook for natural gas is said to be one of abundance and low cost. In this context, "low cost" does not suggest that natural gas will cost less than all other fuels—the price of coal is expected to remain significantly below that of natural gas.[26] Nor does it indicate that natural gas costs and prices will be lower than they have ever been—historically natural gas wellhead prices have only exceeded $4 (in constant 2012 $) during two periods: 1981-1985 and 2000-2008. Nor does it mean that volatility has been eliminated—daily, monthly, and seasonal volatility will continue to reflect unexpected events and temporary misalignment of demand and supply usually caused by variations in weather.

Rather, "low cost" natural gas in the context of the unconventional natural gas revolution indicates that:

- Natural gas prices will not have to increase materially to elicit additional supplies, owing to the extensive resource base that is available at a full-cycle breakeven price of about $4 per Mcf.
- Natural gas prices will remain significantly lower than had been expected prior to the Shale Gale.
- Natural gas prices are expected to remain lower, on a Btu-equivalent basis, than oil products or electricity.

[26] From early 2009 through mid-2013, the dispatch costs of many gas generation units have been lower than those of many coal generation units because, although natural gas prices have been higher than coal prices on a Btu-equivalent basis at times, this disadvantage has been more than offset by gas generation's efficiency or heat rate advantage.

Implications for gas LDCs

The unconventional natural gas revolution has radically changed the outlook for the US natural gas market. Natural gas resources are expected to be available to meet demand for decades to come at prices much lower than were expected just a few years ago. This presents new opportunities for gas LDCs to increase load growth. At the same time, there are opportunities to increase US energy efficiency, reduce emissions of greenhouse gases, revitalize industries, increase US energy security, reduce consumer energy costs, and promote local economic development. The following chapters explore these opportunities in more detail and discuss ways in which local gas distribution companies and their customers can participate in the promised benefits.

Chapter II: The Economic Contributions of US Unconventional Energy

In Brief

- IHS CERA projects that capital expenditures in the oil and gas industry will average some $200 billion per year (nominal $) by 2035 for a total expenditure of more than $5 trillion over this period.
- Unconventional oil and gas activity and energy-related chemical manufacturing were responsible, directly or indirectly, for 2.1 million jobs, nearly $284 billion in value added to gross domestic product (GDP) and more than $74 billion in government tax revenues in 2012. By 2025 these contributions are expected to grow to 3.9 million jobs, $533 billion (constant 2012 $) in value added to GDP, and $138 billion (constant 2012 $) in government revenues.
- The total net trade impact of the unconventional oil and gas revolution is expected to increase steadily, before a plateau of $180 billion per year (constant 2012 $) is reached in the early 2020s.
- Unconventional oil and gas activity and energy-related chemical manufacturing added an estimated $1,200 to real disposable income per household in 2012. This contribution will grow to $2,000 in 2015, and to more than $3,500 by 2025 (constant 2012 $). This increase in household income results from lower costs of natural gas, electricity, and products made from lower cost natural gas and electricity as well as the higher wages that result from the manufacturing renaissance spurred by lower cost domestic natural gas supplies.
- A discussion of energy security can be found in Chapter X on Transport.

A full assessment of the economic contributions of unconventional oil and gas activity involves consideration of:

- The economic benefits arising from capital spending on oil and gas development
- The effects of lower energy prices on the entire economy
- Shifts in trade patterns as US oil, gas and other goods increase their competitive advantage in international markets
- Shifts in the composition of the US economy toward a more significant manufacturing sector

The growth in US oil and natural gas production is fueled by capital spending on exploration and development, which exceeded $87 billion in 2012. Since the majority of the technology, tools, and know-how are home grown, an overwhelming majority of every dollar spent through this supply chain remains in the United States and supports domestic jobs. Extensive supply chains—across many states, including states that do not directly produce unconventional oil and natural gas—reach into multiple facets of the American economy.

As the production of US unconventional oil and natural gas expands over the next 25 years, the industry's economic contribution will also expand. While last year's capital expenditures were over $87 billion, IHS CERA projects that capital expenditures will average some $200 billion (nominal $) per year from 2012-35, for a total expenditure of more than $5 trillion (nominal $) over this period.

This spending will take place in upstream unconventional oil and natural gas activity (including drilling, completion, facilities, and gathering systems) but also will feed into the broader supply chain through purchases of heavy equipment, iron and steel, and rig parts, as well as technical services/skills and information technology. It will then reverberate throughout the economy as workers directly employed in the oil and gas industries and workers employed in industries that supply materials and services to oil and gas operators spend their earnings on food, housing, clothing, entertainment, and other goods and services.

The economic contribution of unconventional energy activity to employment is therefore measured by the sum of (1) the direct contribution, (2) the indirect contribution from supplying industries, and (3) the induced economic contribution that results from workers spending their incomes throughout the entire economy.

IHS Global Insight has estimated that unconventional oil and gas activity and energy-related chemical manufacturing were responsible, directly or indirectly, for 2.1 million jobs, nearly $284 billion in value added to GDP and more than $74 billion in government tax revenues in 2012. By 2025 these contributions are expected to grow to 3.9 million jobs, $533 billion (constant 2012 $) in value added to GDP, and $138 billion (constant 2012 $) in government revenues.[27]

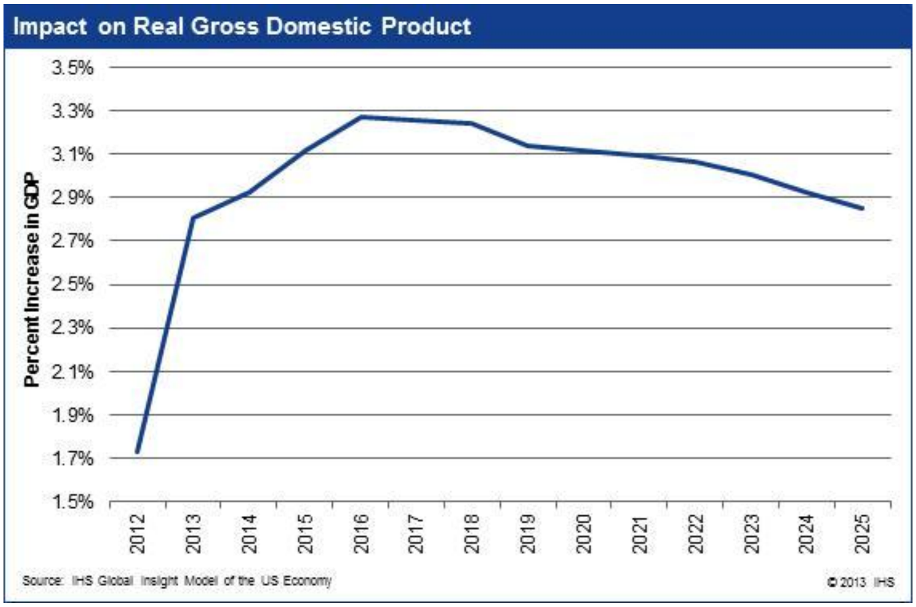
In addition to the significant industry contributions defined above, affordable and abundant natural gas has ushered in an era of prices substantially lower than they would have been without the unconventional revolution. These lower prices are currently providing a short term economic stimulus to disposable income, GDP and employment—a positive force during a period of continued economic uncertainty and slow growth. Three standard macroeconomic metrics—GDP, net trade, and disposable household income experience positive impact as follows.

Gross domestic product

The incremental boost from the unconventional oil and natural gas value chain and energy-related chemicals is expected to add 2% to 3.2% to the value of all goods and services produced in the United States (see Figure II.1). That is forecast to increase rapidly and peak in the early years. Over the short term, the impact of the unconventional oil and natural gas value chains and energy-related chemicals on the level of GDP peaks at 3.2% by 2016. In the context of a $13-15 trillion US economy, this equates to an increase in GDP of $500 to $600 billion.

[27] See the IHS Inc. report America's New Energy Future: *The Unconventional Oil and Gas Revolution and the US Economy*.

FIGURE II.1



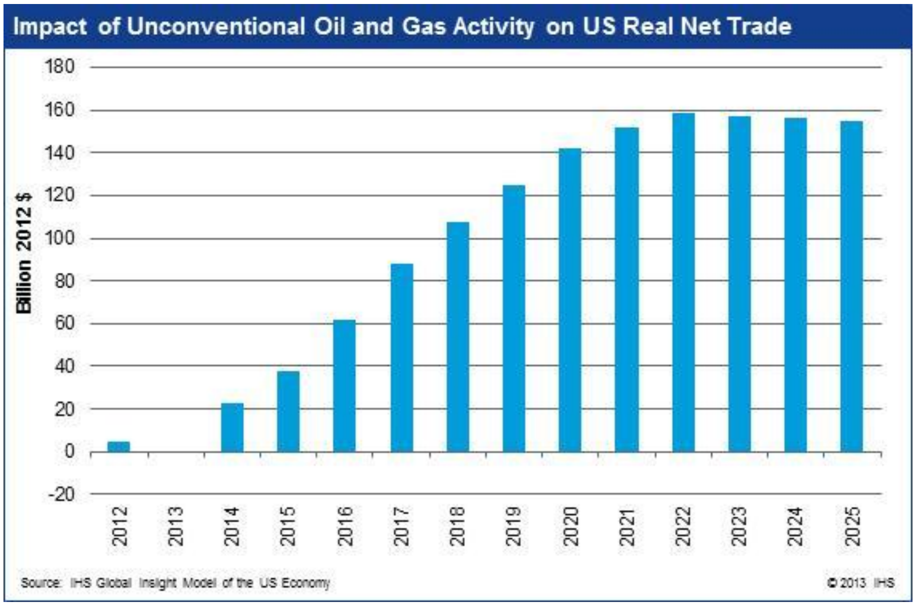
Net trade

The unconventional revolution will also substantially improve the US net trade balance for several reasons. First, the increase in domestic energy production will allow the United States to export significant quantities of intermediate and refined energy products, such as liquefied petroleum gases and liquefied natural gas. Second, for energy products in which the United States is a large net importer, namely crude oil, each barrel of increased production displaces an equivalent imported barrel. Third, reduced energy costs, specifically for electricity and natural gas, improve the global competiveness of energy-intensive manufacturing industries.[28]

Despite declining domestic demand, this new competiveness will enable petroleum refiners to continue operating at high utilization rates, meeting lower domestic demand and then exporting surplus production to Latin America and Europe. The impact on US trade of the unconventional revolution is projected to increase steadily through 2022 before plateauing at a new, higher level of $180 billion per year in additional real net trade relative to a US trade regime in which there was no unconventional activity (see Figure II.2).

[28] An increase in crude oil production of 2.5 mbd by 2025 versus 2012 levels corresponds to a net reduction in the trade deficit of approximately $85 billion per year, using an oil price of $95 per barrel.

FIGURE II.2



Disposable income

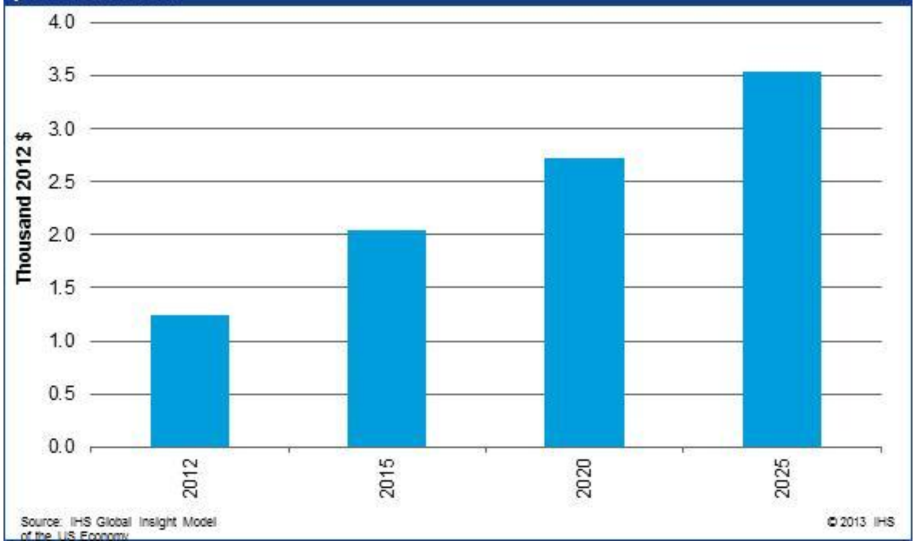
Finally—and most tangibly for American families—household disposable income will rise due to increased activity in the US unconventional oil and natural gas value chain and in energy-related chemicals. This is the cumulative impact of increasing household wages and decreasing costs for energy and energy-intensive products. These factors work through three primary avenues of economic growth:

- Direct consumption costs are reduced as natural gas used to heat homes and water becomes less expensive.
- Input costs for manufacturers of various consumer goods, including electricity prices, decline, reducing indirect costs for consumers.
- Wages increase as the manufacturing renaissance increases industrial activity.

In 2012, the increase in real disposable income per household as a result of the unconventional oil and gas revolution was approximately $1,200 (see Figure II.3). With nearly 120 million households in the country, this equates to total annual savings to American households of $163 billion. These benefits are expected to continue to grow: real disposable income per household will steadily increase over the entire forecast period, from $2,000 per household per year in 2015 to more than $3,500 by 2025.

FIGURE II.3

Impact of US Unconventional Oil and Gas Activity on US Disposable Income per Household



The manufacturing renaissance

A variety of factors have encouraged the manufacturing renaissance currently under way in the United States, including productivity gains for US workers, significant technological advances, and slower growth in hourly compensation relative to our global competitors. These factors have already helped US manufacturing rebound since the trough of the recession in 2009. Manufacturing is continuing to make important contributions to economic growth. Manufacturing's overall real value added—its contribution to GDP—increased 6.2 percent in 2012, after increasing 2.5 percent in 2011. This growth was led by durable-goods manufacturing, which was the largest contributor to US growth overall in 2012. The durable goods manufacturing sector has experienced significant growth for three consecutive years: 13.3 percent in 2010, 6.8 percent in 2011, and 9.1 percent in 2012.[29]

These factors, in combination with the profound impacts of increasing unconventional oil and natural gas production, are revitalizing critical segments of the US manufacturing base. To provide a comprehensive analysis of the economic impact, it is critical to examine the unconventional revolution's effect on major manufacturing industries. US manufacturers are benefitting from the availability of a secure supply of low-cost natural gas, especially manufacturers in energy-intensive industries. Energy-related chemicals, petroleum refining, aluminum, steel, glass, cement, and the food industry are key energy-intensive sectors that are expected to invest and increase their US operations in response to declining prices for their energy inputs.

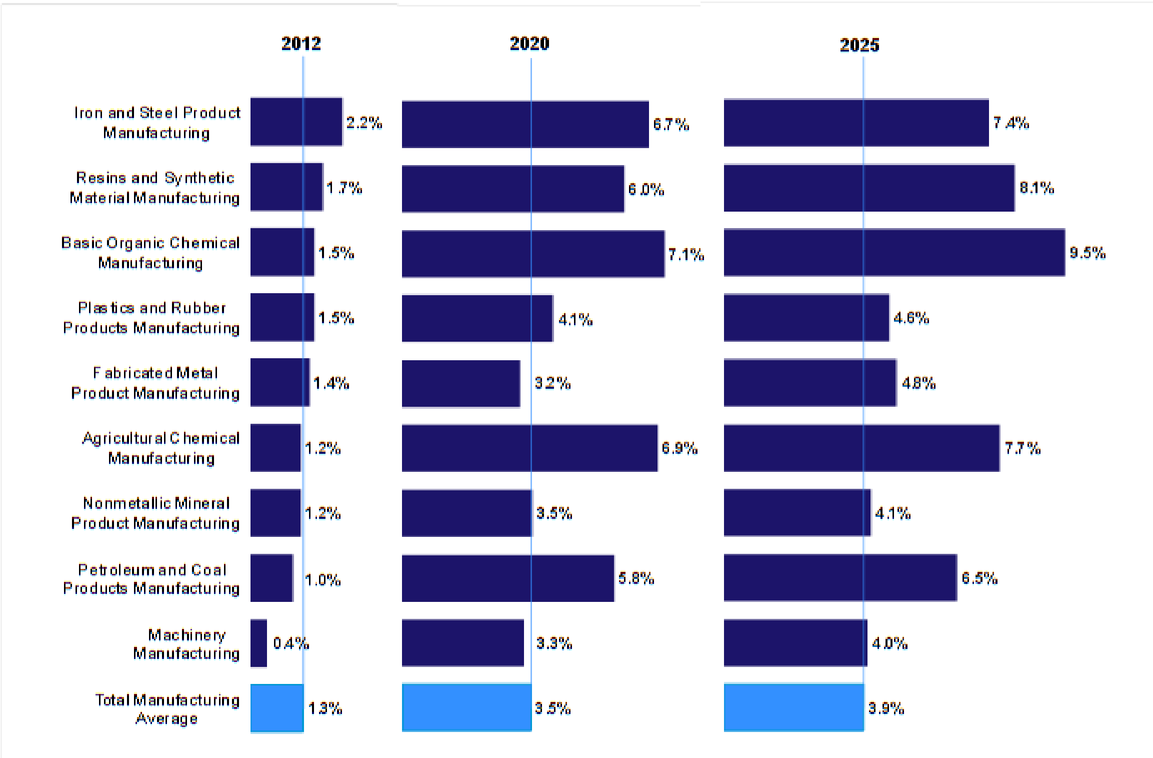
The impact of the unconventional oil and natural gas revolution in the forecast period is pronounced among energy-intensive industries. In 2012, many energy-intensive manufacturing industries outperformed the total manufacturing index average growth of 1.3%. Subsectors such as Iron and Steel Product Manufacturing and Basic Organic Chemical Manufacturing are expected to be well in front of the overall manufacturing average in both 2020 and 2025 (see Figure 11.4). The same can be said for Resins

[29] http://www.bea.gov/newsreleases/industry/gdpindustry/gdpindnewsrelease.htm.

and Synthetic Material Manufacturing (6.0% growth in 2020 and 8.1% in 2025) and Agricultural Chemical Manufacturing (6.9% growth in 2020 and 7.7% in 2025).

FIGURE II.4

Percent Increase to Selected Industrial Production Indices due to the Unconventional Activity Value Chain



Source: IHS, *America's New Energy Future: The Unconventional Oil and Gas Revolution and the US Economy; Volume 3: A Manufacturing Renaissance*, 2013

Beyond the contributions of the unconventional oil and natural gas revolution, there are a number of factors contributing to the resurgence in manufacturing that place the United States in a strong position to expand its manufacturing base further. These factors include:

- Improvements in technology and in the efficiency of manufacturing processes that have shifted the balance away from the importance of low-cost labor and toward a higher skilled workforce
- Changes in relative global manufacturing compensation and productivity levels
- Improved manufacturing efficiencies in the use of energy
- Shortened supply and logistics chains due to research and development resources and end markets that are geographically closer to manufacturing locations

As a result, the broad manufacturing renaissance is not purely a function of the unconventional oil and natural gas revolution. However, while it is important to recognize that these and other factors are contributing to a broad manufacturing renaissance in the United States, the contribution of the unconventional energy revolution has been quantified by IHS macroeconomic modeling based assessment, and it is significant.

Implications for gas LDCs

A revolution is under way in the production of unconventional oil and natural gas that is transforming America's energy economy, with far-reaching effects, both geographically and in numerous sectors of the US economy. Gas LDCs can align with local stakeholders and play a key role in enabling communities to realize these benefits.

Chapter III: Natural Gas and the Environment

In Brief

- Natural gas combustion emits less CO_2 than coal or oil and negligible amounts of SO_2, NO_x, mercury, particulates and ash. The substitution of natural gas for coal in power generation already is tempering the growth of US power sector CO_2 emissions.
- From a full fuel-cycle perspective, natural gas is more energy efficient for many residential and commercial applications than electricity. Electricity production is much less efficient than the direct burn of natural gas, owing primarily to the energy losses in generating electricity (the conversion process) and transporting electricity. In many regions, converting from electricity to natural gas for space heat, water heat, and cooking can increase total energy efficiency and reduce emissions by avoiding electricity conversion losses. Because the current large disparity between retail natural gas prices and retail electricity prices is expected to widen over time, increasing gas' share of these markets can increase cost efficiency as well.
- State governments, public utility commissions (PUCs), and gas LDCs should consider how abundant, reasonable cost natural gas can now be used to help improve total energy efficiency and reduce overall emissions. Policies that support greater use of natural gas should be underpinned by: full fuel-cycle energy efficiency analyses; full fuel-cycle emissions analyses; and life cycle cost analyses. Use of these tools can identify regions and applications where greater natural gas use should be promoted as society will benefit from improved energy efficiency and reduced emissions provided the applications also promote economic efficiency. PUC and gas LDC policies on adding customers and extending service to new markets may need updating to facilitate a shift from site energy efficiency to a full fuel-cycle energy efficiency paradigm.
- Combustion of natural gas results in fewer emissions than other fossil fuels. However, direct emissions of natural gas from production to distribution are of concern since natural gas is primarily composed of methane, which has 28 times the global warming potential of CO_2. Minimizing methane emissions from natural gas systems is an important factor in realizing the climatic benefit of fuel switching from other fossils fuels to natural gas.
- Field production accounts for the majority of methane emissions; however, the accuracy of emissions estimates from unconventional gas production has been challenged and efforts are underway to improve the data. Local distribution systems are believed to emit less methane than most other parts of the supply chain, but modernizing infrastructure, monitoring and leak detection will be important to achieving further reductions.

- Natural gas is not CO_2-free. If natural gas is to be used to further reduce greenhouse gas (GHG) emissions, technologies must be developed to remove CO_2 from the natural gas combustion process. A variety of carbon capture and sequestration (CCS) technologies are under development for use with either coal-fired or natural gas-fired power generation, but significant challenges remain. CCS will make coal- or gas-fired power generation more costly, but gas with CCS is expected to be less costly than coal with CCS. Various research and development projects are underway to try to make CCS more cost-effective, including projects seeking to reformulate natural gas into hydrogen prior to combustion and turn captured CO_2 into saleable products.
- Water management, noise, truck traffic, and local land use are other concerns associated with natural gas development. These issues are being addressed through regulation and industry best practices.

The greatest attraction of natural gas from an environmental perspective is that when combusted it results in the lowest CO_2 emissions of any fossil fuel. When used to generate electricity, natural gas emits as much as 50% less CO_2 than coal. In addition, natural gas use results in negligible emissions of sulfur dioxide (SO_2), nitrogen oxides (NO_x), mercury, and particulates compared with other fuels. Although combustion emissions from power plants are heavily regulated and typically are controlled, Table III.1 provides a baseline level of comparison for emissions rates across fossil fuels. Increasing the use of natural gas in place of other fossil fuels can have both global benefits in terms of reduced GHG emissions and local benefits in terms of lower emissions of SO_2, NO_x, mercury, and particulates in the United States.

TABLE III.1

Emissions from Uncontrolled Fossil Fuel Combustion

lb/MMBtu

	CO_2	SO_2	NO_x	Mercury	Filterable Particulates
Natural Gas	117.647	0.001	0.186	0.026×10^{-5}	0.002
Oil*	162.667	2.093	0.313	0.075×10^{-5}	0.144
Coal**	232.308	2.222	0.462	1.000×10^{-5}	3.846

* Fuel Oil #6 with 2% sulfur content.

**Medium-volatile bituminous coal with 10% ash content and 1.6% sulfur content.

Source: US Environmental Protection Agency

Emissions reductions through energy efficiency can also occur when natural gas is used directly in homes and businesses in place of electric heat and hot water, when assuming the average US generation fuel mix. Chapter V discusses the energy efficiency benefits of natural gas in great detail in the residential and commercial sectors.

Environmental policies—both currently in place and under review—that limit air pollutants are factors supporting the outlook for growth in natural gas consumption, particularly in the power sector. Existing regulations are increasing the cost of operating coal-fired power plants and hastening the retirement of coal units. Challenging economics (relative to natural gas) and the uncertainty of future regulations have virtually eliminated the construction of new conventional coal-fired capacity. IHS CERA expects that new generating capacity for the next two decades will be evenly split between natural gas and renewable generation.

However, this outlook is subject to policy and technological uncertainty. The absence of clear policy guidance on GHG emissions—particularly at the federal level—has frustrated investors who remain uncertain as to which technologies might be favored or disadvantaged over the longer term. And while President Obama's June 2013 Climate Action Plan (and accompanying memorandum) provides some clarity on the schedule for the development and implementation of CO_2 performance standards for power plants, the structure, stringency, and impact of the regulation remain uncertain.

Despite the absence of formal legislative action, regulatory bodies are moving forward under their existing authority with measures that will stimulate increased demand for natural gas. The US Environmental Protection Agency's (EPA) rollout of regulations under the Clean Air Act (CAA) to control CO_2, mercury, and other air toxics will disproportionately affect coal-fired electric power generation to the benefit of natural gas. EPA is also requiring significant reductions in GHG emissions from other sectors, including the transportation sector. Specifically, EPA and the US Department of Transportation (DOT) adopted new fuel efficiency standards in fall 2012 that require unprecedented GHG emission reductions in fuel economy standards for light-duty vehicles by 2025.

Natural gas does possess one potential disadvantage from an environmental perspective, however. Natural gas is about 95% methane and methane has about 28 times the global warming potential of CO_2 when it is emitted into the atmosphere rather than combusted.[30] Direct emissions of methane into the atmosphere—whether from upstream operations, leaks in the pipeline and distribution systems, or accidents anywhere within the natural gas system—have environmental consequences. Minimizing methane emissions from natural gas production, processing, transmission, and distribution is an important factor in realizing the climatic benefit of fuel switching from other fossils fuels to natural gas. Environmental concerns associated with water and land use also have arisen with the increased development of unconventional natural gas in recent years. These issues are all addressed in the following sections of this chapter.

Greenhouse gas emissions

US federal policy relating to GHG emissions is being developed and implemented by EPA through regulations primarily aimed at limiting CO_2 emissions from the combustion of fossil fuels rather than incentivizing the penetration of cleaner technologies. President Obama's 2013 Climate Action Plan and accompanying Presidential Memorandum explicitly direct EPA to complete CO_2 performance standards for fossil fuel-fired power plants on a very specific timeline. In particular, it directs EPA to re-issue proposed CO_2 standards for new power plants and finalize them expeditiously and to issue proposed and final standards (in the form of guidance to states) for existing power plants by June 2014 and June 2015, respectively. The Memorandum went a step further in prescribing the regulatory timeline by specifying that EPA require states to submit implementation plans for regulating existing power plant CO_2 emissions by June 2016 (see the box "EPA rolls out CO_2 regulations for the power sector").

These regulations emerged after a series of legal events that occurred dating back to 2007, which resulted in subsequent rules that collectively compel EPA to regulate GHG emissions from stationary sources

[30] The global warming potential (GWP) for a particular greenhouse gas is the ratio of heat trapped by one unit of mass of the greenhouse gas to that of one unit of mass of CO_2 over a specified time period, in this case 100 years. Methane also has a relatively short atmospheric lifetime of 12 years, meaning that its GWP is higher over shorter time frames than the 100 years typically used in climate analysis. *Fifth Assessment Report of the Intergovernmental Panel on Climate Change (IPCC)*, Geneva, Switzerland, 2013.

under the CAA. EPA issued a draft regulation to limit the level of CO_2 emissions from large, new coal- and gas-fired power generators in April 2012. This regulation was later withdrawn, and EPA issued a new version of the regulation in September 2013. EPA will now begin work on a separate but related regulation to reduce CO_2 emissions from existing fossil fuel generation. These regulations have been and will continue to be vigorously challenged in the courts. They are also potentially vulnerable to legislative action that could remove or curb EPA authority to regulate GHG emissions. If they are upheld, they are likely to secure the position of natural gas as a leading fuel source to meet new electric power demand and to replace retiring coal-fired generation over the next 20 years.

EPA rolls out CO_2 regulations for the power sector

On 20 September 2013, EPA released its much anticipated proposal to regulate CO_2 emissions from *new* fossil fuel–fired power plants, which replaced an earlier draft released in April 2012. The rule (which would expand the New Source Performance Standards [NSPS] for new power plants to include CO_2 emissions) proposes separate standards for natural gas- and coal-fired power plants. The rule proposes that new, large gas-fired units (burning more than 850 MMBtu per hour) meet a CO_2 emission threshold of 1,000 pounds per megawatt hour (MWh); smaller gas-fired units would be subject to a lower threshold of 1,100 pounds of CO_2 per MWh. New coal-fired units would need to meet a CO_2 threshold of 1,100 pounds per MWh, or operators could opt for more stringent limits (1,000 to 1,050 pounds per MWh) in exchange for the flexibility of averaging emissions over several years. New conventional coal plants would only be able to meet these standards with the application of CCS technology, which has yet to be demonstrated on a commercial-scale at power plants. The proposed rule will be open for public comment for 60 days following publication in the Federal Register. The rule is expected to be challenged in court. If upheld, it would effectively eliminate new conventional coal as an option for power generation and thereby remove a major choice in power generators' fuel diversification strategies.

EPA has also recently begun the process of developing CO_2 performance standards for existing power plants under a separate provision of the CAA. President Obama has directed EPA to finalize this rule (in the form of guidance to states to develop specific implementation plans) by June 2015. The section governing existing sources is broad and relatively unused. In the past, EPA has used it primarily to establish unit-level emission performance standards. However, in regulating CO_2 emissions all indications are that EPA will put forth a rule that includes considerably greater compliance flexibility, including allowing for market-based trading programs.

Two potential market-based regulatory mechanisms that could be proposed as models for states to adopt, either individually or in coordination with other states, are: 1) a CO_2 emissions cap and trade program (i.e., a limit on total power sector emissions) or 2) a tradable performance standard (i.e., a requirement that fossil generating units achieve a specified average emission rate). Such programs would introduce a degree of flexibility and reduce overall CO_2 emissions from covered sources more efficiently than would a unit-level based emission performance standard. EPA may also choose to include additional forms of flexibility, such as giving compliance credit for additional renewable power generation or demand-side efficiency measures. Some stakeholder proposals believe measures, such as energy efficiency initiatives, use of combined heat and power, and replacement of consumer electrical equipment with natural gas equipment, should be acceptable forms of flexibility. However these latter forms of flexibility are apt to invite more legal scrutiny and could be more vulnerable to court challenges creating uncertainty. Regardless of how much flexibility is incorporated, this rule is likely to place disproportionate pressure on existing coal-fired power generation vis-à-vis existing natural gas-fired generation in the 2020s and accelerate the retirement of some coal units.

While EPA continues down the path of regulating CO_2 emissions from power plants under the CAA, various legislative proposals for alternative approaches to reducing emissions continue to circulate quietly. Over the past five years, numerous bills have been introduced in the US Congress that proposed alternative policy mechanisms such as a federal renewable electricity standard (RES), a clean electricity standard (CES), a CO_2 cap-and-trade scheme, and a CO_2 tax. Although the US House of Representatives passed one of these bills in 2009 (*The American Clean Energy and Security Act of 2009*, HR 2454, sponsored by Representatives Waxman and Markey), none have become law. Moreover, momentum for alternative mechanisms has slowed recently in the face of a new political dynamic in Congress and pressing fiscal issues that are commanding their attention. As controversy mounts surrounding EPA CO_2 regulations under the CAA, it is possible that a legislative compromise could emerge that would replace CAA regulation with a market-based approach.

The Obama administration recently increased its estimate of the social cost of CO_2 emissions, which is used to evaluate the climate benefit of rulemakings.[31] The mid-range estimate, given at a 3.0% discount rate, increased from $26 to $41 per ton for 2015.[32] Social cost estimates are used to estimate the economic impact and would likely bound the acceptable cost of any federally proposed GHG policy.

In addition to federal CO_2 policy, several states are advancing market-based policies aiming to reduce CO_2 emissions from the power sector. In the case of California, state policy seeks emissions reductions from multiple sectors. While meaningful developments have recently occurred in the two most notable programs, they will have only a modest impact on the power generation fuel mix.

- The Regional Greenhouse Gas Initiative (RGGI) multi-state CO_2 cap-and-trade program recently announced plans to significantly reduce the overall cap on CO_2 emissions from electric power generation starting in 2014, with gradual declines thereafter.[33] The program adjustment will place modest additional pressure on coal-fired generation this decade, to the advantage of natural gas-fired generation, but likely not enough to accelerate the pace of coal plant retirements.[34]

- The California GHG cap-and-trade program is also progressing, with the launch of the state-wide program in 2013. The program is expected to drive a more significant market-based price for CO_2, and will moderately affect the power generation fuel mix and CO_2 emissions. However, a portfolio of other targeted policies will have significant influence, including those that will increase renewable power generation (renewable portfolio standard), reduce contracted coal-fired power generation outside the state (SB 1368), and require the retirement/repowering/replacement of coastal gas-fired steam generators through the elimination of once-through cooling (California's state water quality control policy on the use of coastal and estuarine waters for power plant cooling.).

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[31] According to EPA, the social cost of CO_2 is intended to be a comprehensive estimate of climate change-related damages that includes, but is not limited to, changes in net agricultural productivity, human health, and property damages from increased flood risk.

[32] The social cost estimates were opened to public review and comment on 5 November 2013 and hence are subject to potential change.

[33] RGGI was first launched in 2009. Nine states currently participate in the program, which places an overall cap on the emissions from fossil fueled power generators with capacities of 25 megawatts (MW) or more. Generators must procure (through auction or secondary markets) enough RGGI CO_2 allowances (permits to emit) to cover CO_2 emissions associated with their production. The nine states currently participating in RGGI are Connecticut, Delaware, Maine, Maryland, Massachusetts, New Hampshire, New York, Rhode Island, and Vermont.

[34] Two states, Maine and New Hampshire, must pass legislation before the program adjustment can take effect.

Power sector CO_2 emissions

As gas-fired power generation displaces coal-fired generation CO_2 emissions from the US power sector have declined.[35] The decline in the spread between natural gas and coal prices that began in the spring of 2009 altered the competitive position of natural gas-fired power generators in many US markets and caused a significant amount of coal generation to be displaced by lower CO_2-emitting gas generation. In 2012 US power sector CO_2 emissions were the lowest that they have been since 1995—16% below emissions in 2005 (an often used baseline year). While sluggish growth in power demand contributed to the decline, it was mainly a result of natural gas-fired generation displacing coal-fired generation. As reflected in Figure III.1, however, power sector CO_2 emissions are expected to rebound from 2012 lows as natural gas prices recover in the near term, albeit to moderate price levels.

Over the remainder of this decade, moderately priced natural gas will contribute to decisions to retire significant amounts of coal-fired generating capacity and thus temper the rebound in US power sector CO_2 emissions. Owners of older, less efficient coal plants confronting the capital investments necessary to be in compliance with non-CO_2 environmental regulations (covered below) are concluding that retirement is the right economic choice given the forward looking competitive position of these assets relative to those fueled by natural gas.

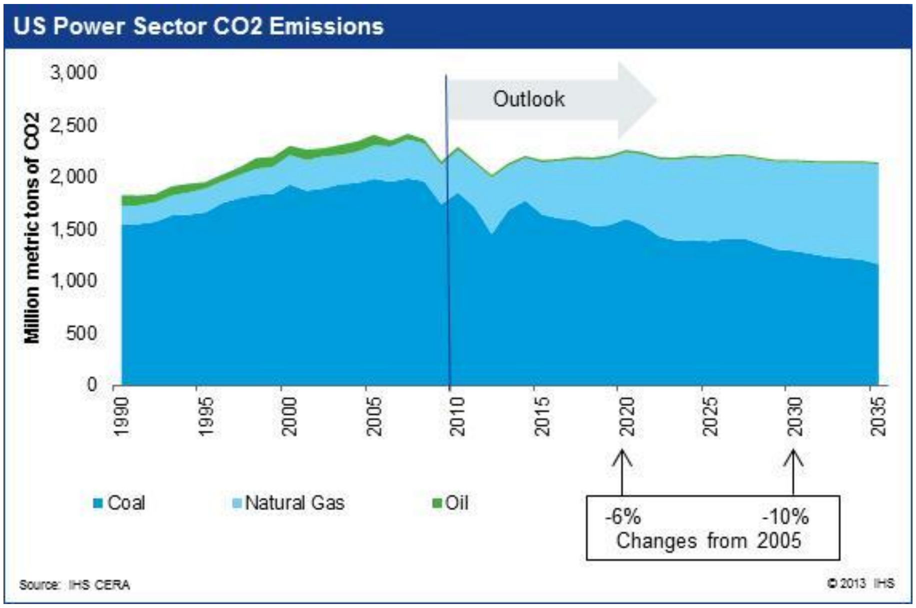
Other power sector environmental policy and considerations

In addition to developing regulations to address power sector CO_2 emissions, EPA is also in the process of implementing and finalizing several previously proposed rules intended to address other forms of power plant emissions:

- The **Mercury and Air Toxics Standards (MATS) Rule** would establish unit-level emission standards for mercury and other air toxics.
- A **replacement for the Clean Air Interstate Rule,** which was struck down in court but allowed to remain in effect on a provisional basis pending a suitable replacement. A rule is intended to help eastern states meet National Ambient Air Quality Standards (NAAQS) for fine particulates and ozone by limiting the downwind transport of two major precursors, SO_2 and NO_X emissions.
- The **Regional Haze Rule** establishes air pollution control retrofit technology requirements for SO_2, NO_X and particulate matter (PM) emissions to help restore visibility in national parks, forests, and wilderness areas to natural levels.
- The **Coal Combustion Residuals Rule** (also sometimes referred to as the Coal Ash Rule) would regulate the solid waste by-products of coal-fired electricity production (e.g., fly ash, bottom ash, boiler slag, and scrubber sludge) following either non-hazardous waste or hazardous waste protocols.
- The **Cooling Water Intake Structures Rule** would regulate cooling water withdrawals at existing thermal power plants.
- Updates to **Effluent Limitation Guidelines** regulate the discharge of wastewater from thermal power plants.

[35] When natural gas is used instead of nuclear energy for power generation however, CO_2 emissions from the power sector increase as nuclear generation does not emit CO_2.

FIGURE III.1



The compliance burden associated with these rules will largely fall on coal-fired power plants. As previously discussed, if each rule were to go into effect as currently proposed, many coal plants would be required either to make significant retrofit investments or to retire beginning in the 2015-17 timeframe. Natural gas-fired power plants, on the other hand, are not expected to be significantly affected by these rules. They emit no SO_2, PM, or hazardous air pollutants, a *de minimis* volume of effluent, and approximately one-fifth as much NO_X (on a generation-weighted average basis), since virtually all baseload natural gas plants have post-combustion NO_X controls.

Transportation sector CO_2 emissions

EPA also has been active in regulating GHG emissions from vehicles, since the transportation sector accounts for 31% of US CO_2 emissions. In September 2012, EPA issued new GHG standards in conjunction with fuel economy targets established by the National Highway Traffic Safety Administration (NHTSA) for the 2017-25 time frame, building on standards already established for 2012-2016. These aggressive standards target a 54.5 miles per gallon-equivalent (mpg_e) for the light duty fleet, including passenger cars and light-duty trucks, in model year 2025. Due to the stringency of the requirements and recognition of the difficulty in forecasting market conditions, a mid-term evaluation due not later than April 2018 was included in the regulation. At this time, EPA and NHTSA will use the evaluation to make a recommendation for maintaining the stringency established for 2022 to 2025, adding more compliance flexibility, or relaxing the requirements. Many parameters will be evaluated such as the state of the economy, employment trends, the cost and availability of advanced technology, and the impact of the new standards on occupant safety, all potentially leading to some form of modification to the 2022-25 mpg targets.

The CO_2 emission benefit of low-cost natural gas in transportation has been slower to emerge thus far. US natural gas consumption in on-road transportation is very small—approximately 117 MMcf per day in 2012. IHS CERA expects this volume to triple by 2020 to about 340 MMcf per day, but natural gas use in vehicles will remain a small proportion of total vehicle fuel use. As a result, increased natural gas use in vehicles will have a modest overall impact on CO_2 emissions. While policy has and will continue to play a role, the price differential between natural gas and other on-road transport fuels will be a major force driving this trend (see Chapter X).

Carbon capture and storage

Reduction of CO_2 emissions is a major technological challenge for the power industry. Baseload power generating technologies that do not emit CO_2 (or emit very little) are needed if the CO_2 intensity of the sector is to be reduced in a meaningful way, and a portfolio of technologies will be required to meet long-term climate policy targets. This includes not only energy technologies that emit no CO_2 such as renewables, nuclear power and hydro power, but also technologies such as CCS that remove CO_2 from the combustion of fossil fuels.

CCS is a crucial technology in retaining the relevance of fossil fuels in a world concerned about serious climate change. CCS for power plants is a complex value chain that includes:

- Capture of CO_2 from combustion of fossil fuels
- Pipelining the recovered CO_2 to disposal sites
- Storage or sequestration of CO_2 in underground natural reservoirs
- Monitoring, measurement and verification of CO_2 while in storage

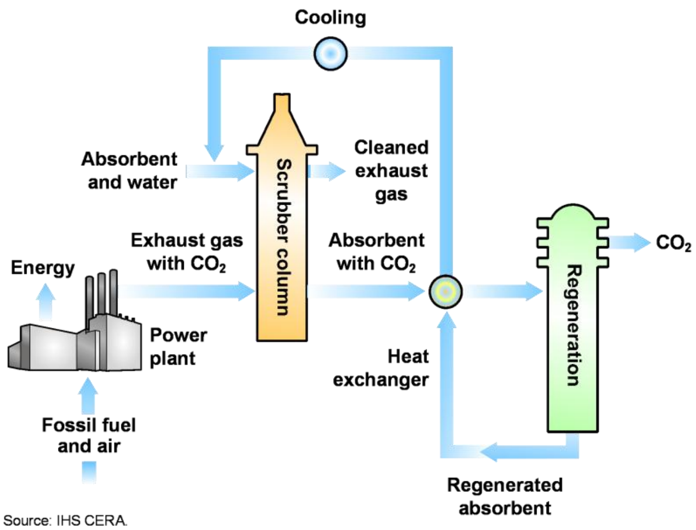
CCS technologies

Removal of CO_2 during the combustion of fossil fuels can be accomplished in three ways—post-combustion mode, pre-combustion mode or in an oxyfuel process. Post-combustion capture is the most commonly employed method today. It involves passing a power station's entire exhaust stream through a chemical solvent (see Figure III.2). The CO_2 saturated solvent is then regenerated into a concentrated CO_2 stream and the solvent recycled for further use. The process of removing CO_2 requires energy and power, resulting in high parasitic losses. For new power plants capturing 90% of their CO_2 emissions, IHS CERA expects power plant parasitic losses to range from 25-35% for coal and 15-25% for natural gas-fired baseload plants.

Post-combustion recovery using amines or chilled ammonia to absorb and capture the CO_2 is most relevant for natural gas. While such technologies are commercially available, they are expensive and involve significant parasitic power losses of 25-35% due to power consumption from the capture and solvent recovery process.

FIGURE III.2

Post-Combustion Carbon Capture Process

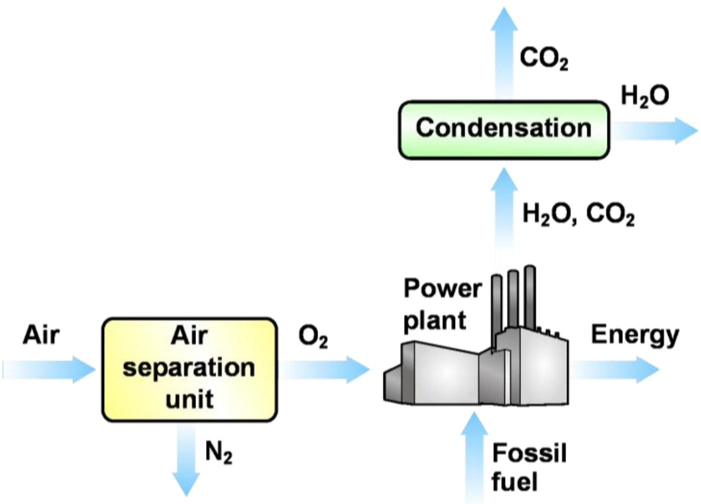


Source: IHS CERA.
91114-1_08IV

Oxyfuel combustion involves the low temperature (cryogenic levels) removal of inert nitrogen from the air stream to produce a concentrated stream of combustible oxygen, which reduces the volume of gas being processed (see Figure III.3). Processing the CO_2 stream results in slightly lower parasitic losses (25-30%) than parasitic losses from using the post-combustion method. This process can be used to remove CO_2 from any fossil fuel.

FIGURE III.3

Oxyfuel Carbon Capture Process

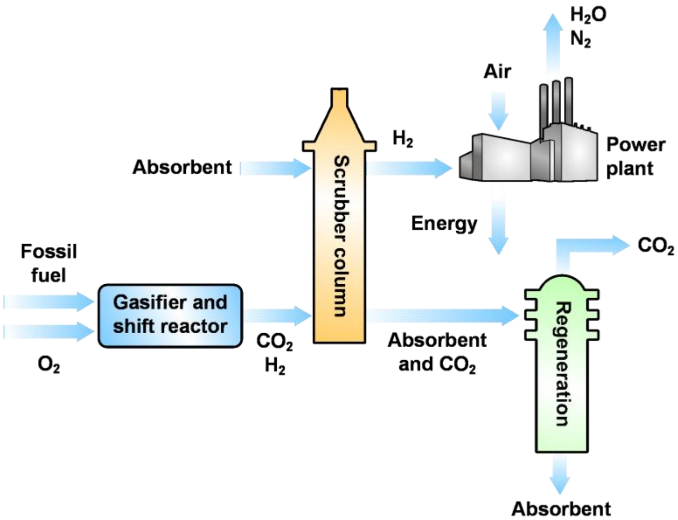


Source: IHS CERA.
91114-3_21111

Pre-combustion or integrated gasification combined cycle (IGCC) technology is applicable only to solid fuels (coal or petroleum coke). The fuel is converted to syngas (a combination of carbon monoxide and hydrogen) using a gasifier (see Figure III.4). The higher concentration of CO_2 produced and higher pressure results in somewhat lower parasitic losses of around 20%.

FIGURE III.4

Pre-Combustion Carbon Capture Process



Source: IHS CERA.
91114-2_21111

All of these technologies are currently in use at the semi-commercial or commercial levels but are almost exclusively based on coal.

CO_2 transportation, storage and monitoring trends

CO_2 transportation via pipeline is a mature technology with well-defined costs. Many such pipelines already exist to move CO_2 to enhanced oil recovery projects on a commercial scale.

Sequestration on the large scale required for extensive CCS use is still an immature technology with an uncertain regulatory regime. In addition, some lingering doubts exist on the behavior of pressurized CO_2 under different reservoir conditions. Liability issues include the potential for leakage of large volumes of CO_2 as well seismic or earthquake activity induced by CO_2 storage. Corporations are likely to press governments to assume these potential storage risks.

Reservoirs with high porosity and permeability are best suited for sequestration. Generally storage must be at a depth of at least 2,500 feet to maintain integrity of the supercritical CO_2. However, at greater depth the absorptive capacity of pore space decreases due to increasing pressure. Extensive drilling is required to identify suitable storage sites. Moreover, research into induced seismicity from energy development (discussed further below) suggests that the large volume of potential fluids injected into underground CCS storage reservoirs could produce earthquakes.[36]

In addition, large uncertainty exists regarding the amount of CO_2 that can be accommodated in pore space. Some studies suggest as little as 2-3% of CO_2 can be accommodated. If this were the case, a high number of injection wells would be required ranging from 5-100 wells per gigawatt of power. One of the major underappreciated factors in carbon storage is the scale. A 1,000 MW coal-fired power plant emits

[36] National Research Council, *Induced Seismicity Potential in Energy Technologies*, Washington, DC, 2012, www.nap.edu.

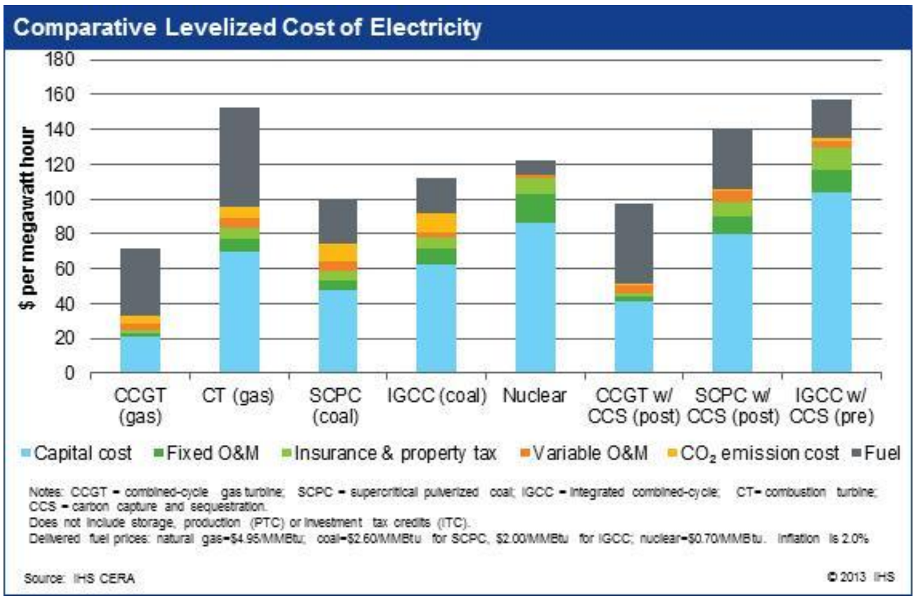
about 24,000 tons of CO_2 each day. This volume of CO_2 would require a reservoir equivalent to 10,000 acres and a formation thickness of 100 feet each year. Some experts believe the sheer massive scale of storage is one reason that this technology will never truly attain commercial status.

The final part of the CCS value chain is the development of an effective measurement, monitoring and verification procedure for the CO_2 stored in reservoirs.

Cost and technological factors affecting CCS

A coalescence of high capital costs for CCS, low natural gas prices and uncertainty as to climate change policy is challenging for the economics of CCS. On paper, the levelized cost of a CCGT plant with CCS is much lower than that of a coal-fired plant with CCS. Nonetheless, IHS CERA estimates that on a levelized cost basis the cost of natural gas-fired generation with CCS technology is still more than 45% higher than the cost of natural gas-fired generation without CCS technology (see figure III.5).

FIGURE III.5



One CCS technology gaining some traction today is the recovery of CO_2 from power plants for use in enhanced oil recovery (EOR) where a revenue stream can be paid to the emitter by oil developers.[37] The application of EOR (also called tertiary oil recovery) can increase the amount of oil extracted from a field by over 50%. Because of the scale of such projects and volumes of CO_2 required, this technology strongly favors CO_2 from coal-fired plants rather than the more dilute streams and smaller scale CO_2 volumes from CCGT facilities. In addition, power plants and host EOR projects are required to be in reasonable proximity to minimize the cost of pipeline transmission. Furthermore, EOR is not applicable to every oil field; some oil wells respond much more positively than others. Uncertainty also exists around how much CO_2 is sequestered in its use as a tertiary fluid and how much leaks back to the surface and into the atmosphere.

Technologies currently in their infancy are being developed to improve the cost-effectiveness of CCS for natural gas and create end-use markets for captured CO_2. For example, one technology under development

[37] The Dakota Gasification subsidiary of Basin Electric has since 2000 been capturing and selling CO_2 from the combustion of lignite for transportation to an EOR operation located 205 miles away in Saskatchewan.

includes using electrochemistry to convert CO_2 to energy and chemical products such as methanol and formic acid. Other innovations seek to produce electricity from natural gas without generating CO_2 emissions through pre-combustion removal of CO_2. The technology is designed to process natural gas into hydrogen and solid CO_2 so that the hydrogen can be used to generate electricity from fuel cells and the CO_2 sold for use in manufacturing or industrial processes.

CCS remains a slowly evolving technology that is largely happening only in combination with government financial support (e.g. in Canada and the United States). The focus to date is overwhelmingly on CO_2 emissions from coal-fired power plants with little focus on the much lower CO_2 emissions from CCGTs. CCS could be commercially feasible in the United States in the mid-2020s provided the following occur over the coming decade: a CO_2 policy is enacted that limits unit-level CO_2 emission rates and/or imposes a price on CO_2; continued government support is provided for research, development, demonstration and deployment of the technology; outstanding liability issues are resolved; and learning from first-of-a-kind full-scale demonstration projects leads to reductions in the cost to build and operate future plants.

Environmental issues related to natural gas development

There are a number of environmental issues involved in developing unconventional gas resources. These include:

- The intensity of development associated with drilling multiple wells from a single pad, including impacts on local communities
- Water management and disposal
- Induced seismicity
- Greenhouse gas emissions

These issues are manageable with prudent development and with the use of best practices in well construction; all require industry involvement with local communities and with federal, state, and local regulators.

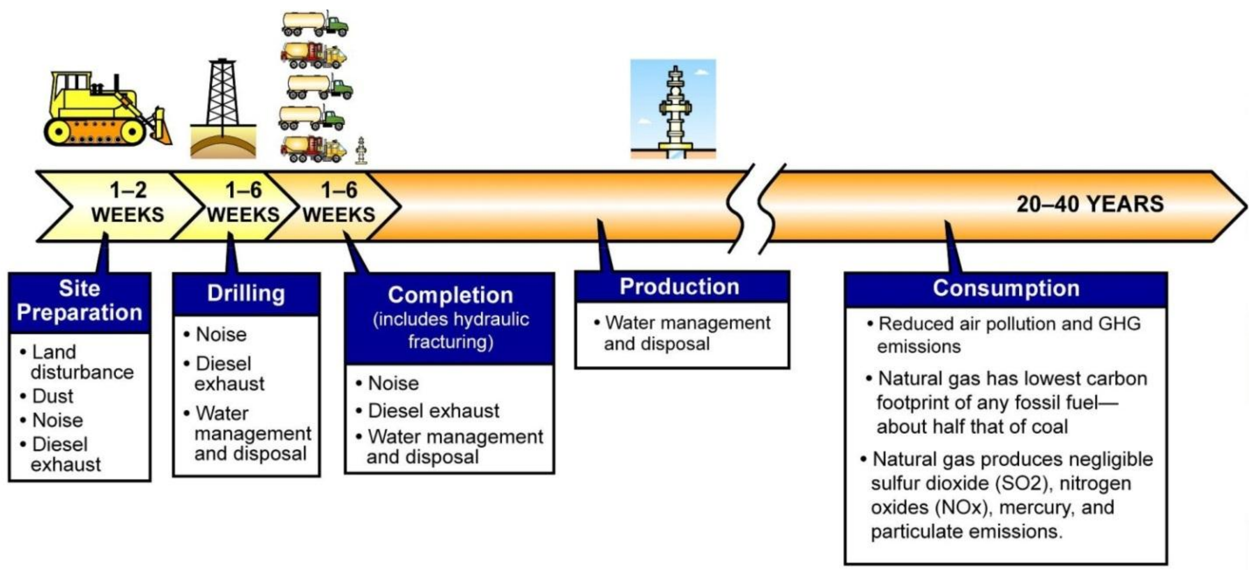
Intensity of development

The process of natural gas development involves site preparation, drilling, well completion (the stage that involves hydraulic fracturing) and production (see Figure III.6). Most of the adverse effects from development—land disturbance, dust, noise, vehicle traffic, and emissions of diesel exhaust, CO_2 and methane—occur during the 2-12 weeks required to drill and complete a well. Once the well is in production, the management and disposal of fluids that come out of the formation along with the gas are the major remaining environmental concerns. Nevertheless, the process of drilling and completing a well is a round-the-clock operation. Pad operations, which involve the drilling and completion of several wells, can continue for months before all wells are connected to a gathering system and pipeline and go into full production. The construction of gathering lines, processing plants, and pipelines to connect new gas supply areas to market areas are additional, but also temporary, disruptions.

Once all wells on the pad have been connected to a gathering system and pipeline, the disturbances that were tolerated during site preparation, drilling and completion are offset by the environmental benefits of natural gas consumption during the 20 years (or more) that the wells remain in production. Some companies employ landscape beautification initiatives, typically in urban areas, to improve the aesthetic appeal of the well site while it remains under production. Fences and shrubbery are often employed to block sound and improve the appearance of the site so that it blends in with neighborhood surroundings.

FIGURE III.6

Timeline for Natural Gas Development



Source: IHS CERA.
00502-3

In many respects, the environmental effects associated with pad drilling may be lower than the disruptions that would result from producing an equivalent amount of natural gas from conventional wells from multiple sites. Because unconventional gas wells are more productive than conventional wells, natural gas production has increased while the number of gas wells drilled each year has plummeted. From 2008 to 2012, natural gas production in the US Lower 48 grew from 54.1 Bcf per day to 64.9 Bcf per day. Over this same period, the number of natural gas wells drilled declined from more than 32,000 per year to less than 15,000 per year (see Chapter I). Because unconventional wells are increasingly drilled from pads with multiple wells, their environmental effects are more concentrated. However, the use of pads to drill several wells at the same site reduces the land acreage required as compared to the total land acreage required for separate well sites.

Water management and disposal

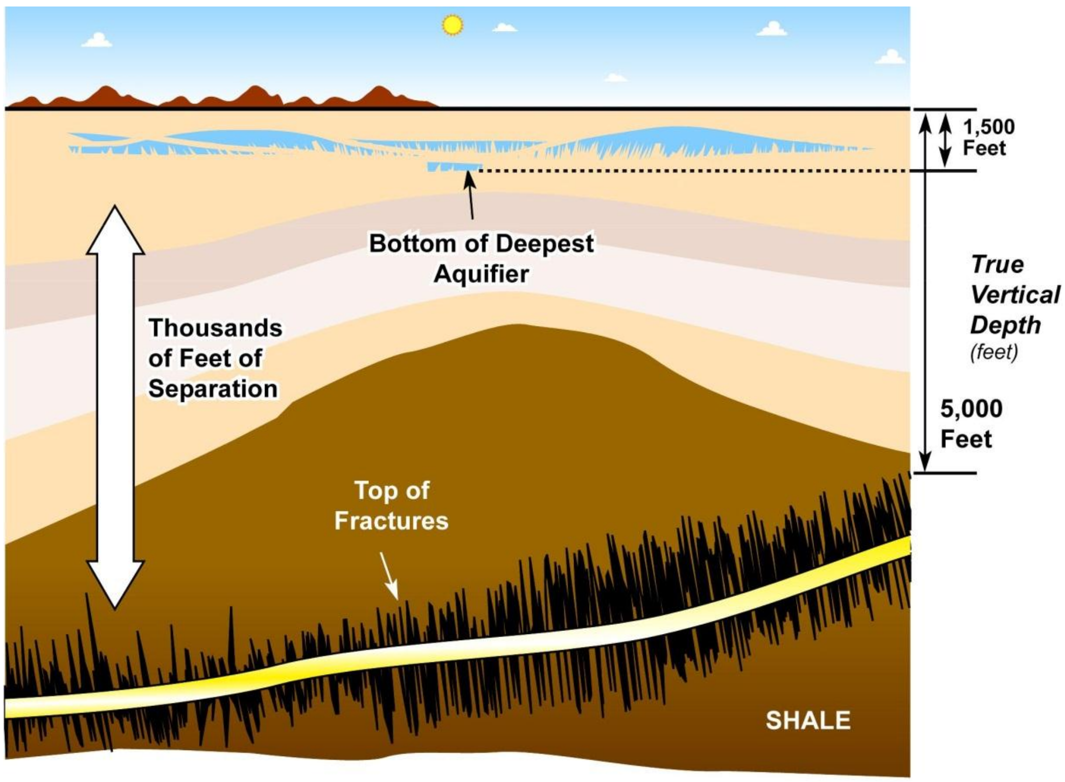
Several million gallons are needed to drill and fracture a single unconventional gas well, but shale gas development in the United States accounts for less than 0.1% of total US annual water consumption . However, large volumes of water are required over a short duration of time in the weeks that a well is drilled and completed. Large volume requirements at a single point in time can challenge water resources. Industry has developed low-water drilling technologies that reduce up front water requirements and are treating and re-using wastewater in drilling and completion operations. Some operators are recycling as much as 95% of their wastewater.

During the fracturing process water is mixed with chemicals and sand before injection into the well. This has led to the emergence of environmental and community concerns about the chemical composition of fracturing fluid. Companies have become more forthcoming with respect to disclosure of the chemicals used in hydraulic fracturing. Many operators are participating in FracFocus—a voluntary online registry for operators to list the chemicals used in each well. In addition, many states (and the Federal Government in the case of drilling on public lands) have begun to require such disclosure.

A consensus has developed that migration of natural gas from the source rock upwards through thousands of feet of impermeable formations into drinking water aquifers is highly unlikely, if not impossible (see Figure III.7). An emphasis on proper well construction has emerged as the best defense against water contamination, and industry and regulators have strengthened their focus on best practices.

FIGURE III.7

Separation between Drinking Water Aquifers and Hydraulic Fractures

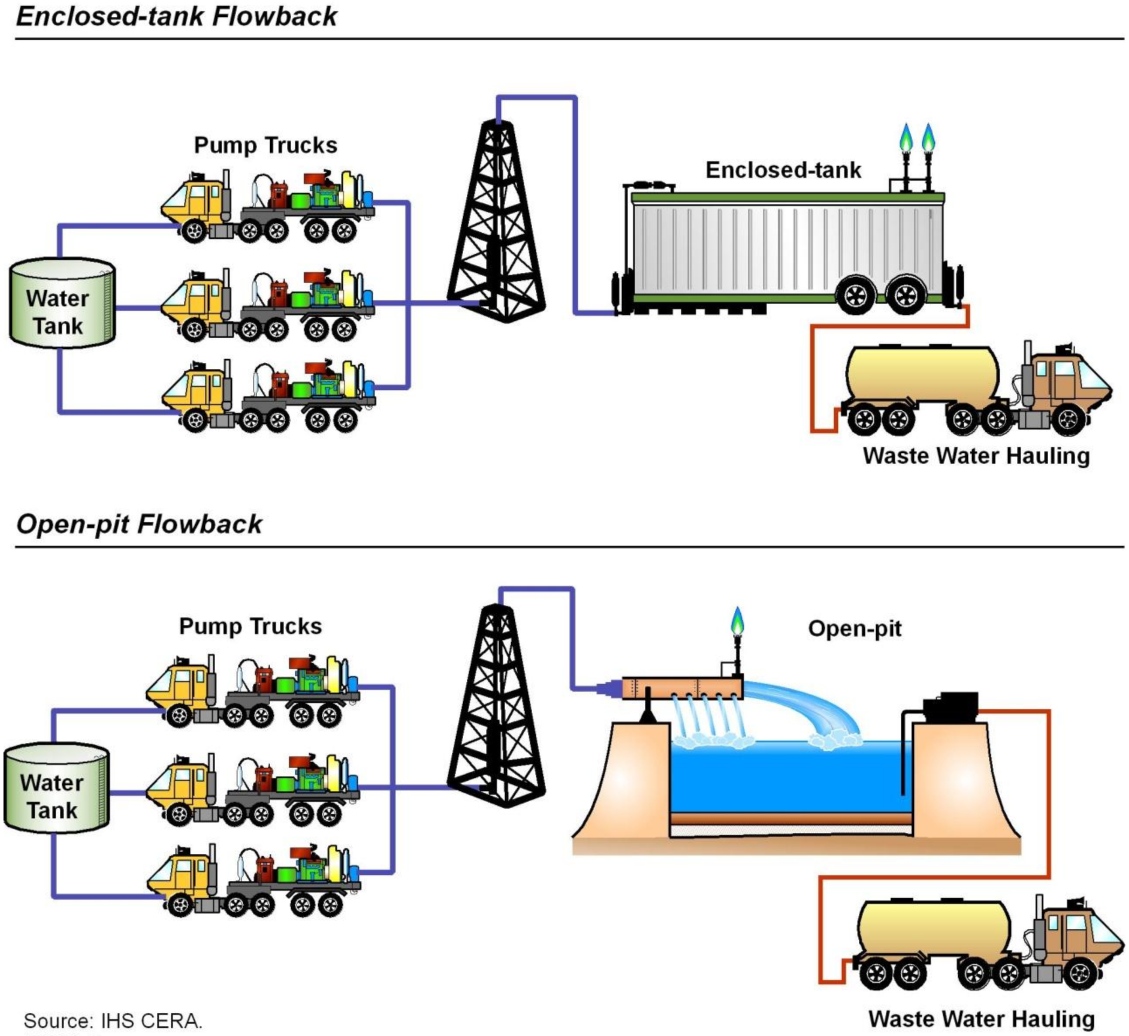


Source: IHS CERA.
Note: Based on the North American Resource Development study "Prudent Development," 2011, National Petroleum Council.
11102-3

Wastewater disposal has presented challenges in some areas because shale gas wells are so productive and large volumes of fracturing fluids and formation water flow to the surface along with the natural gas produced by each well. The preferred method of wastewater handling at the well site is closed-tank storage, although open-pit storage is also widely used (see Figure III.8). In both cases, any natural gas contained in the wastewater is flared rather than vented directly into the atmosphere—thereby releasing CO_2 rather than methane—to keep GHG emissions to a minimum.

FIGURE III.8

Basic Post-Fracturing Flowback Configurations



Source: IHS CERA.
10802-3

Wastewater can be treated and reused at the well site or transported off site for disposal, most often into underground injection wells. Wastewater disposal into underground injection wells is regulated by EPA under the Safe Drinking Water Act.[38] The EPA regulates surface water disposal under the Clean Water Act, and state agencies may also regulate waste treatment and surface water disposal.

Induced seismic activity

Although several low-level earthquakes and tremors in England and Canada have been attributed to hydraulic fracturing, similar instances of induced seismicity in the United States were related not to hydraulic fracturing itself but rather to injection of wastewater from fracturing operations into underground disposal wells. These incidents occurred in Arkansas, Colorado, Texas, Ohio, and

[38] Generally the EPA allows states to administer the regulation of underground disposal wells.

Oklahoma. A 2012 study[39] by the National Research Council found that:

1. The process of hydraulic fracturing a well as presently implemented for shale gas recovery does not pose a high risk for inducing felt seismic events.

2. Injection for disposal of wastewater derived from energy technologies into the subsurface does pose some risk for induced seismicity, but very few events have been documented over the past several decades relative to the large number of disposal wells in operation.

3. CCS, due to the large net volumes of injected fluids, may have potential for inducing larger seismic events.

The study cited change in the "net fluid balance (total balance of fluid introduced into or removed from the subsurface)" as the most likely cause of the seismic events. It also noted that such events have been associated not only with oil and gas development, but with geothermal energy development as well.

Greenhouse gas emissions from natural gas systems

Natural gas is primarily composed of methane, which is a much more potent GHG than CO_2. Methane can be released in the production and delivery of natural gas through intentional venting or unintended leakages. Operational or infrastructure constraints when wells are being drilled and completed may prevent initial quantities of natural gas from being moved to market immediately. In such cases, the gas may be vented (releasing methane) or flared (releasing CO_2). Industry practice is to market the gas as soon as produced volumes are adequate, and to flare it until then. However, infrastructure constraints can be significant, particularly in the case of associated gas from oil plays. IHS CERA estimates that about 0.3 Bcf per day of associated gas production is being flared from the Bakken oil play, releasing CO_2 into the atmosphere, owing to a lack of gathering, processing and pipeline infrastructure to take the gas to market.

In its latest *Inventory of US Greenhouse Gas Emissions and Sinks (Inventory)* report, EPA estimates that 53.4 teragrams CO_2-equivalent ($TgCO_2e$) of methane and 10.8 Tg of CO_2 were released into the atmosphere from upstream natural gas operations in 2011, comprising slightly less than 1% of total US GHG emissions. EPA's methodology for estimating methane emissions from natural gas field production, particularly unconventional gas production, has been heavily criticized in recent years.[40] In response, EPA made significant revisions to the emissions factors and activity levels used to generate their estimates, resulting in significant changes in estimates across all years reported in the 2013 *Inventory*. For example, the 2010 methane emissions estimate from natural gas field production decreased from 126 $TgCO_2e$ to 57.2 $TgCO_2e$ and the 1990 estimate decreased from 89 $TgCO_2e$ to 60.8 $TgCO_2e$ (see Table III.2).[41]

A number of industry, university, and environmental groups are working to collect better data on methane emissions from unconventional natural gas development, as well as from transmission, storage, and distribution.[42] EPA's Greenhouse Gas Reporting Program (GHGRP) included reporting from natural gas and petroleum systems for the first time in its 2011 data set (released February 2013). This program requires operators to submit emissions data, which are primarily developed from calculations using emissions factors rather than direct measurement. However, these data are expected to improve over time

[39] National Research Council, *Induced Seismicity Potential in Energy Technologies*, Washington, DC, 2012, www.nap.edu.

[40] See the IHS CERA Private Report *Mismeasuring Methane*.

[41] US Environmental Protection Agency, *Inventory of US Greenhouse Gas Emissions and Sinks: 1990-2011* (12 April 2013) and *Inventory of US Greenhouse Gas Emissions and Sinks: 1990-2010* (15 April 2012).

[42] For example: Allen, David et al, *Measurements of Methane Emissions at Natural Gas Production Sites in the United States*, Proceedings of the National Academies of Sciences, September 2013.

as more direct measurement of industry activity occurs and more accurate emissions factors can be developed. These data will be used to help improve estimates of upstream and downstream methane emissions in future Inventories.

Developing better estimates on methane emissions is paramount to understanding the climate benefit of fuel switching from other fossil fuels to natural gas. According to one study, new combined-cycle natural gas power plants produce net climate change benefits relative to new efficient coal plants as long as emissions from the natural gas system, including from field production through delivery to the power plant, amount to less than 3.2%.[43] Emissions data from EPA and production data from EIA indicate that leakage[44] in the natural gas system is below this threshold. Experts agree that EPA natural gas methane emissions estimates are uncertain with large margins of error (many of the source estimates were generated based on twenty-year-old research) that could significantly affect the estimated leakage rate. However, these estimates are likely to change and uncertainties will be narrowed as the results from new field testing become available and as EPA's emissions methodology continues to be refined. More robust research and validation of industry emissions is underway to ensure the perceived benefit of fuel switching to natural gas.

TABLE III.2

EPA Estimates of Methane Emissions from Natural Gas Field Production

Tg CO_2-equivalent

	1990	2005	2006	2007	2008	2009	2010	2011
2013 Inventory	60.8	75.5	86.8	83.1	76.4	61.9	57.2	53.4
2012 Inventory	89.0	105.2	133.8	117.8	123.2	129.4	126.0	
2011 Inventory	89.2	105.4	134.0	118.2	122.9	130.3		
2010 Inventory	34.2	23.9	25.0	18.4	14.1			

Source: *Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2011, 1990-2010, 1990-2009, 1990-2008*

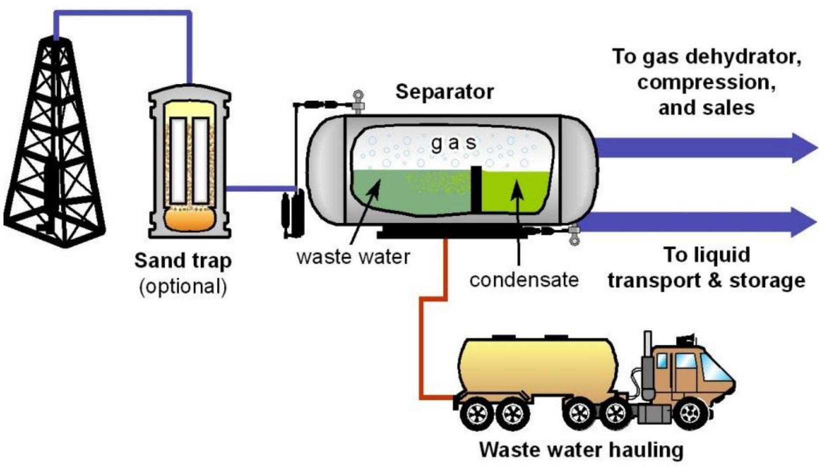
A new EPA regulation finalized in 2012 requires all operators to use "reduced emissions completions" or "green completions" on wells drilled after 1 January 2015, subject to limited exceptions. This completion technology is designed to capture most methane emitted during well flow-back for sale (see Figure III.9). The technology includes running the flowback fluids through a sand trap to remove solids materials and then through a separator to remove condensate and water. The condensate is sent to market and water is hauled away for disposal or recycled into future well completions. The equipment is portable so that it can be moved to the next site once well completion has concluded. Such systems are already widely used throughout the United States and are mandated by several states.

[43] Alvarez, Ramon, et al., *Greater Focus Needed on Methane Leakage From Natural Gas Infrastructure*, Proceedings of the National Academy of Sciences, 13 February 2012, http://www.pnas.org/content/109/17/6435.

[44] We use the term leakage broadly applies to all methane emissions that occur during the production, transmission, distribution and storage of natural gas as well as fugitive leaks and vented emissions.

FIGURE III.9

Next Evolution Flowback: Reduced Emissions Completion



Source: IHS CERA.
30602-1

In terms of methane emissions throughout the natural gas supply chain, the latest EPA Inventory shows a clear downward trend since 2007, and by 2011 emissions were lower than estimated 1990 levels. Total industry methane emissions were an estimated 144.7 TgCO_2e in 2011 compared to 168.4 in 2007 and 161.2 in 1990 (see Table III.3). Methane emissions from pipeline and storage facilities are estimated to have been 43.8 TgCO_2e in 2011—up from the estimated 2005 level of 39.5 but still considerably lower than the 1990 level of 49.2. The gas distribution industry has consistently lowered its methane emissions over this period, from 33.4 TgCO_2e in 1990 to 27.9 in 2011.

TABLE III.3

Estimated Greenhouse Gas Emissions from Natural Gas Systems

Tg CO_2-equivalent

	1990	2005	2007	2008	2009	2010	2011
CH_4							
Field Production	60.8	75.5	83.1	76.4	61.9	57.2	53.4
Processing	17.9	14.2	15.2	15.9	17.5	16.5	19.6
Transmission/Storage	49.2	39.5	40.8	41.2	42.4	41.6	43.8
Distribution	33.4	29.8	29.3	29.9	28.9	28.3	27.9
Total	**161.2**	**159.0**	**168.4**	**163.4**	**150.7**	**143.6**	**144.7**
CO_2							
Field Production	9.8	8.1	9.5	11.1	10.9	10.9	10.8
Processing	27.8	21.7	21.2	21.4	21.2	21.3	21.5
Transmission/Storage	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Distribution							
Total	**37.7**	**29.9**	**30.9**	**32.6**	**32.2**	**32.3**	**32.3**
Total GHG							
Field Production	70.6	83.6	92.6	87.5	72.8	68.1	64.2
Processing	45.7	35.9	36.4	37.3	38.7	37.8	41.1
Transmission/Storage	49.3	39.6	40.9	41.3	42.5	41.7	43.9
Distribution	33.4	29.8	29.3	29.9	28.9	28.3	27.9
Total	**198.9**	**188.9**	**199.3**	**196.0**	**182.9**	**175.9**	**177.0**

Source: US Environmental Protection Agency

In addition to methane, some CO_2 is emitted from upstream natural gas operations, primarily from flaring. Methane and CO_2 are also emitted in gas processing, pipeline, storage, and distribution operations. According to EPA, methane can escape from faulty compressor seals in gas processors, CO_2 can be emitted by acid gas removal units, and methane can escape through leaks in transmission and distribution pipelines as well as from compressor stations along natural gas pipelines and at storage facilities. CO_2 emissions from pipeline, storage, and distribution systems are negligible.

Regulation of unconventional natural gas development

In response to the unprecedented growth in natural gas (and oil) development across the United States over the last half-decade, state, federal, and even local municipal bodies have been tightening the rules governing drilling and completion activities. In some cases, environmental and safety concerns voiced by the public, press, and other stakeholders have also influenced the regulatory process.

Individual states generally regulate oil and gas operations. State regulations tend mostly to codify best-in-class industry operating practices. Rules and guidelines generally seek to ensure consistent adherence to good practices that protect water quality, air quality, and other aspects of safety and to provide information transparency.

Federal regulation may be involved when activity, materials, or contamination could potentially cross state boundaries. The EPA rule requiring green completions (discussed above) is an example of federal regulation over activities that have interstate effects, as is EPA implementation of the Clean Water Act. Other federal regulation involves oil and gas development on federal and Native American lands. The US Bureau of Land Management has proposed regulations to require public disclosure of fracturing fluid composition, improve assurances on wellbore integrity, and confirm that operators have a water management plan in place.

Although most of the emerging regulations place some compliance burden on operators, they provide a framework for responsible operations under a consistent set of best practices and rules, closing loopholes where shortcuts might have been taken that could result in accidents and unintended consequences. The incremental rules put in place over the past few years have not slowed growth in drilling and production, supporting the view that reasonable regulations are not likely to materially inhibit developing and producing hydrocarbon supply in North America.

Emerging regulations aim to construct a consistent framework to mitigate the safety and environmental concerns associated with well construction and completion practices, although no amount of rules and regulations can completely eliminate the risk of an accident and unintended consequences. Key producing states are likely to set the stage for rules and regulations surrounding oil and gas development, and states will contribute to fine-tuning those rules and regulations over time.

Implications for gas LDCs

Natural gas is the most environmentally attractive fossil fuel. Natural gas combustion emits less CO_2 than coal or oil and negligible amounts of SO_2, NO_x, mercury, and particulates. Substituting natural gas for coal in power generation has significantly reduced US CO_2 emissions. There are environmental caveats to increasing natural gas use, however. Accordingly, care must be taken throughout the natural gas supply chain to minimize methane emissions. For gas LDCs this means working to eliminate leaks throughout distribution systems. And, as with any fossil fuel, natural gas will ultimately require CCS technology to remove and sequester the CO_2 emissions from natural gas use if natural gas is to make longer-term contributions to the management of atmospheric concentrations of GHG. IHS CERA estimates that gas CCS would add about 45% to the cost of gas-fired generation, but gas with CCS retains a significant cost advantage over coal with CCS for power generation.

Energy efficiency benefits are discussed in detail in Chapter V.

Chapter IV: Gas LDCs and Residential/Commercial Demand Growth

In Brief

- The primary drivers of residential and commercial natural gas demand are population growth and the rate of improvement in energy efficiency. Growth in population has and is expected to continue to occur mostly in the South and West, areas which have lower heating requirements but higher cooling requirements. Since 1990, these drivers have essentially offset each other resulting in little or no growth in residential and commercial natural gas demand.
- To change the historical growth paradigm, natural gas has to:
    - Increase its share of residential or commercial fuel through conversions from fuel oil or electricity for single family and multi-family households or commercial customers
    - Improve the competitiveness of natural gas furnaces versus electric heat pumps
    - Install significant numbers of home refueling units for natural gas vehicles (NGVs) or construct significant numbers of compressed natural gas (CNG) refueling stations
    - Achieve transformational breakthroughs in micro combined heat and power (microCHP) units or fuel cells
    - Chapters IX and X examine consumer, industry, and policy challenges to microCHP and light duty NGV adoption, respectively, as well as opportunities to overcome barriers to their adoption. Realizing these opportunities will be quite challenging and may require a rethinking of policies and programs by policymakers, PUCs and gas LDCs.
- With concerns about natural gas availability and price subsiding, there is a clear opportunity for gas LDCs to increase deliveries to existing customers and expand their systems to serve new customers. Chapter VI discusses challenges to expanding gas LDC systems as well as ways to overcome such challenges. However, considerable marketing efforts and changes in regulatory policies and LDC practices may be required in many gas markets.
- One way to expand natural gas use in core gas LDC markets is to replace existing electric and oil appliances with natural gas appliances. In most regions, a natural gas furnace or water heater can have significant cost and efficiency advantages over a comparable oil or electric appliance. However, where additional pipeline capacity is required, the high up front LDC costs and, in some cases, difficulty in getting regulatory approvals for the expansion may slow the rate of conversions. Furthermore, high installation costs can act as a barrier to conversions. As discussed in Chapter VI, there are ways to address the up front cost issue while avoiding higher rates for existing customers and protecting competing fuel suppliers.

This chapter focuses on gas LDCs and their core residential and commercial natural gas markets including the gas LDC's perspective on growth. The role that PUCs play in affecting gas LDC deliveries is reviewed. Primary drivers of residential and commercial gas demand are examined at both the national and regional level. Opportunities for gas LDCs to grow their markets by converting residential and commercial users of fuel oil to natural gas service are examined. Gas and electric competition is analyzed. The chapter concludes with a discussion of new markets and technologies that could reshape the gas LDC residential and commercial natural gas market.

With concerns about natural gas availability and price subsiding, there is a clear opportunity for gas LDCs to increase deliveries to existing customers and expand their systems to serve new customers. However, considerable marketing efforts and changes in regulatory policies and LDC practices may be required in many gas markets, issues that are addressed in this chapter as well as in Chapters V and VI.

The US gas local distribution company industry

The US natural gas distribution system is one of the foundations of the American economy and American life. Gas LDCs deliver gas supply within market areas to customers using 1.2 million miles of smaller diameter, low-pressure mains and approximately 880,000 miles of customer service lines that deliver gas from a street connection to the customer's meter (see Figure IV.1).[45] Gas LDCs serve more than 65 million residential customers, more than 5 million commercial customers, and over 190,000 industrial and power generation customers. Almost all residential and commercial gas users rely on gas LDCs for their gas purchases and/or deliveries (see Figure IV.2). Perhaps surprisingly, 95% of all industrial gas customers and 70% of all power generation customers also depend on gas LDCs for their gas deliveries, although in terms of gas volumes, only about half of the gas used in the industrial sector and only about 25% of gas used for power generation go through a gas LDC system. Some gas LDCs offer bundled gas and distribution services and some offer only distribution services. For 2011, bundled gas services accounted for 88%, 56%, and 17%, of gas LDC residential, commercial and industrial deliveries, respectively.[46] Very large gas-using industrial and power facilities are often not served by gas LDCs, but instead are directly connected to pipelines.

Gas LDCs are a very diverse group. There are over 1,200 gas LDCs in the United States that are investor owned, municipally owned or owned by co-operatives. Gas LDCs range from very small to very large in terms of number of customers, throughput and geographic area served. Climate conditions of markets served vary significantly. Market characteristics, operating parameters and rates and tariffs are very diverse. Some gas LDCs own storage and high pressure transmission lines. This structural diversity makes it hard to generalize about gas LDC business models.

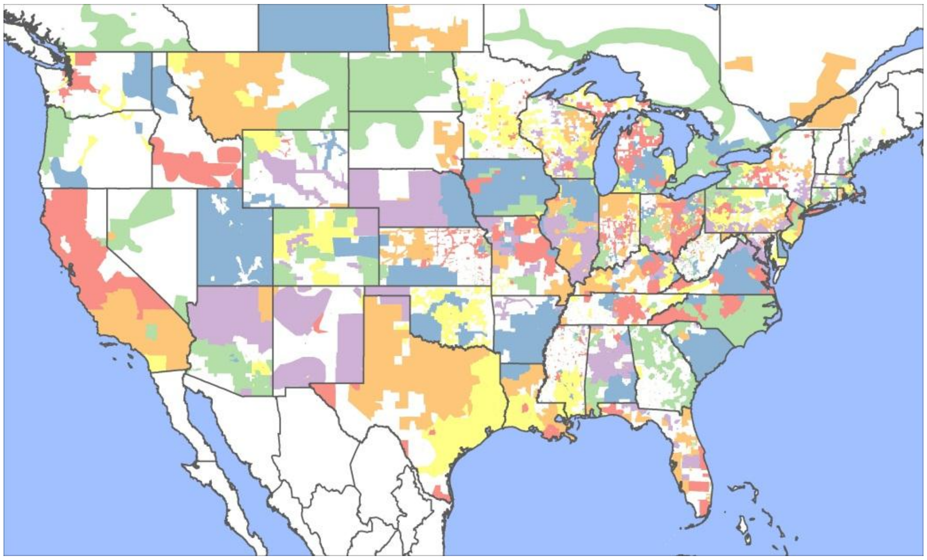
Gas LDC services, rates and facilities are regulated by 49 state PUCs or by their municipal or co-operative owners. Some PUCs have appointed commissioners, some have elected commissioners, but all are subject to political pressure. The policy objectives of PUCs are usually set by legislation and those policy objectives vary across states and time.

FIGURE IV.1

[45] American Gas Foundation, *Gas Distribution Infrastructure: Pipeline Replacement and Upgrades Cost Recovery Issues and Approaches.*

[46] US Energy Information Administration, *Natural Gas Annual 2011*.

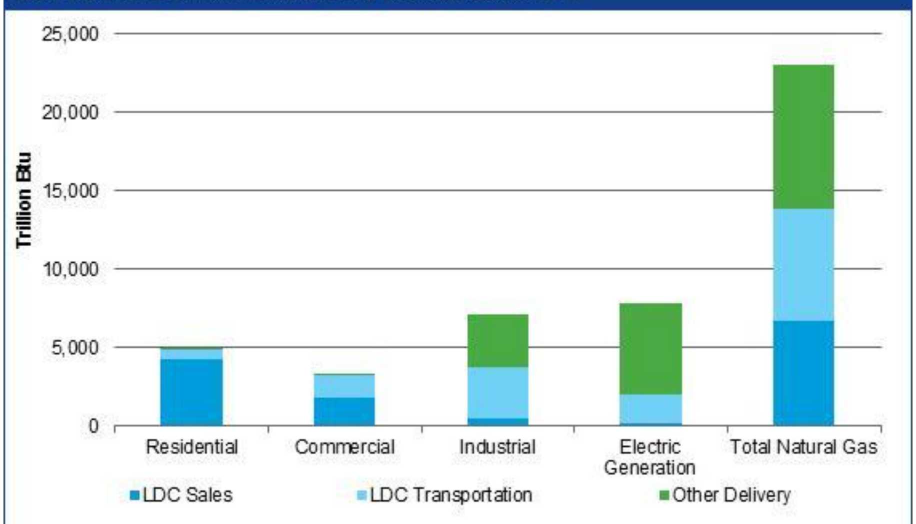
US Gas Local Distribution Company Service Areas



Source: IHS CERA, Ventyx

FIGURE IV.2

Gas LDC and Other Natural Gas Deliveries in 2011



Source: American Gas Foundation

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The focus of Chapter IV is on residential and commercial customers that make up the core of the gas LDC customer base and load. Natural gas LDCs have steadily increased the number of residential customers served, adding almost 16 million residential customers between 1990 and 2011, a 31% increase. At the same time, residential gas customers have reduced their gas consumption by about 1.2% per year since 1990 as homes and appliances have become more energy efficient, and as population has shifted from colder to warmer regions where structures require less space heating. As a result, overall weather normalized gas consumption for the residential sector has been essentially flat from 1990 to 2011. In the commercial sector, there has been about a 26% increase in commercial gas customers from 1990 to 2011.[47] With natural gas demand per commercial customer declining at about 0.6% per year since 1990, weather normalized commercial natural gas demand increased only 14% from 1990 to 2011.

Role of public utility commissions (PUCs)

Local gas transportation, commonly referred to as distribution service, moves natural gas from the "city gate" (i.e., the point of interconnection between the interstate or intrastate pipeline system and the local distribution system) to end users of gas. These end users typically include homes, businesses, industrial facilities, and, in some cases, electric generating plants. Local distribution service is usually a monopoly service; that is, a single company usually serves a local area, with the company usually protected from competition by state law.[48] Most gas LDCs have exclusive rights to provide gas services in a designated geographic area although Ohio does not have certified areas. The grant of exclusivity usually comes with an obligation imposed on the gas LDC to serve all current and prospective gas customers provided it is economic to do so.

Within each state, PUCs have many roles including regulating services such as gas distribution, electric distribution, generation and transmission, telecommunications, and water. The principal function of a regulator is to act as a surrogate for market forces for companies considered monopolistic, such as gas LDCs that have franchise rights. PUCs focus on whether rates and services are just and reasonable and whether facilities are required by the public convenience and necessity.

State PUCs play a vital role in regulating the natural gas sector. Although the marketplace determines the commodity price of gas and the FERC sets maximum rates for interstate pipeline transportation and storage services, PUCs (or other public authorities such as municipalities) approve purchased gas adjustments clauses allowing gas costs to be recovered without a profit and tariff rates to allow recovery of distribution costs including a return on capital invested.

There is a great diversity in gas LDCs' rate structures and tariffs as well as PUC regulatory policies and objectives. Some have policies and practices that better facilitate adding new uses, or new gas customers. Some policies and practices of both PUCs and gas LDCs were developed in an era when there was a concern about the adequacy of gas supply to serve existing customers, let alone gas supply for new customers. During this era, policy responses by federal and state governments, as well as PUCs, included promoting energy efficiency for gas appliances and stricter building codes that improved thermal efficiency of buildings. Adding new gas customers or expanding service to existing gas customers was rarely promoted and, in the 1970s, even prohibited in some areas.

[47] US Energy Information Administration.

[48] Some states allow multiple gas LDCs to serve the same area.

Gas LDCs' perspective on role of PUCs

From the gas LDC's perspective, the bottom line is that they will not pursue investments or programs unless they have a reasonable opportunity to recover their costs, even if there are significant non-monetary societal benefits such as reductions in emissions or economic development. Furthermore, gas LDCs are also not likely to pursue investments or programs that increase their financial risk unless compensated for doing so. For most gas LDCs, their assessment of the likelihood of cost recovery is the most important variable in their decision making. It colors everything they do.

Growth from the gas LDC perspective

Gas LDCs increase revenues and earnings primarily by increasing the rate base on which they are allowed to earn a return. In addition, gas LDCs have the ability to increase earnings between rate cases by adding customers and/or by achieving throughput that exceeds the amount considered in the development of existing rates. An individual gas LDC's strategy for growth will be heavily influenced by its rate structure, tariffs, PUC policies, state laws and market characteristics.

Gas LDCs' rates are set by regulators at a level intended to recover their costs of distribution, including a "just and reasonable" rate of return on invested capital (or rate base). Gas LDCs are not allowed to mark up the cost of the gas that they deliver through their system—and in some cases the gas itself has been purchased by the customer from a third-party.[49] Most gas LDCs have two-part rate structures that allocate costs to a fixed monthly customer charge and a volumetric or usage charge. The usage charge includes the cost of the gas and the variable costs that the gas LDC incurs in delivering the gas to the customer. The LDC's fixed costs are usually split between the customer charge and the usage charge in proportions that differ from one gas LDC to another.

Generally speaking, a gas LDC with a high proportion of its fixed costs in the usage charge will recover more of its costs if it delivers more gas to consumers and risks under-recovering its costs when deliveries decline. For such gas LDCs, increasing deliveries to existing customers—such as customers with gas water heaters who choose to replace an oil furnace with a natural gas furnace—would add to the volume of gas delivered by the gas LDC, but it would not necessarily add to the gas LDC's rate base unless new facilities were required to serve the higher load. Gas LDCs whose fixed costs and rate of return are partly allocated to the commodity charge will see higher fixed cost recovery and earnings from delivering greater volumes of gas to existing customers. These benefits are likely to be temporary if in the next gas LDC's rate proceeding, throughput units for rate design purposes include the incremental volumes. For gas LDCs to increase their rate base, and thereby increase profits, they must add new customers and/or expand their system into new service areas. Rate base and gas LDC earnings can also be increased if the gas LDCs have to invest in new or replacement facilities to maintain operational integrity and reliability, but such investments could increase customer rates unless the customer base also grows.

Gas LDCs whose rates are subject to decoupling adjustments are largely indifferent in the short run to the volumes delivered on their system, but they too stand to benefit from system expansions (see the box

[49] According to the US Energy Information Administration, for 2012 LDCs supplied 96%, 65%, and 17% of the gas delivered to residential, commercial and industrial customers, respectively. The balance of the gas was supplied by third parties.

"Revenue decoupling programs"). However, in the long run, the gas LDC value proposition with the customer should be favorably affected by the amount of natural gas applications used in the home or building and how those applications meet the needs of the customer.

In addition to delivering gas, gas LDCs may find opportunities to increase revenue by offering other services to gas consumers, such as managing gas deliveries to power plants and industrial facilities or providing retail storage service and balancing services to customers with interruptible pipeline service. Rate structures may have to be modified to encourage gas LDC diversification into such services. Gas LDC regulation—and the issue of cost recovery for system expansions in particular—is discussed in more detail in Chapter VI.

Revenue decoupling programs

Revenue "decoupling" programs or other "lost revenue adjustment mechanisms" compensate gas LDCs when efficiency gains reduce their gas deliveries. Typically, decoupling mechanisms take the form of periodic rate adjustments wherein customers will pay a surcharge if gas LDC revenues have fallen short of full cost recovery or they will get a refund (or negative surcharge) if revenues have exceeded full cost recovery. The gas LDC's underlying rate structure is not changed.

Gas LDC core markets: residential and commercial

Residential and commercial customers make up the bulk of gas LDC system deliveries and account for almost all gas LDC sales service. Conversely, most residential and commercial customers are heavily dependent on gas LDCs for their gas supply except for those customers that have chosen, or have the option, to take distribution-only services. Unlike many power plants or industrial facilities, virtually no residential or commercial gas users obtain their natural gas directly from an interstate or intrastate pipeline except for a few "farm taps" usually granted in return for rights-of-way.

Residential and commercial customers use natural gas primarily for space heating, followed by water heating and cooking (see Figures IV.3 and IV.4.)

FIGURE IV.3

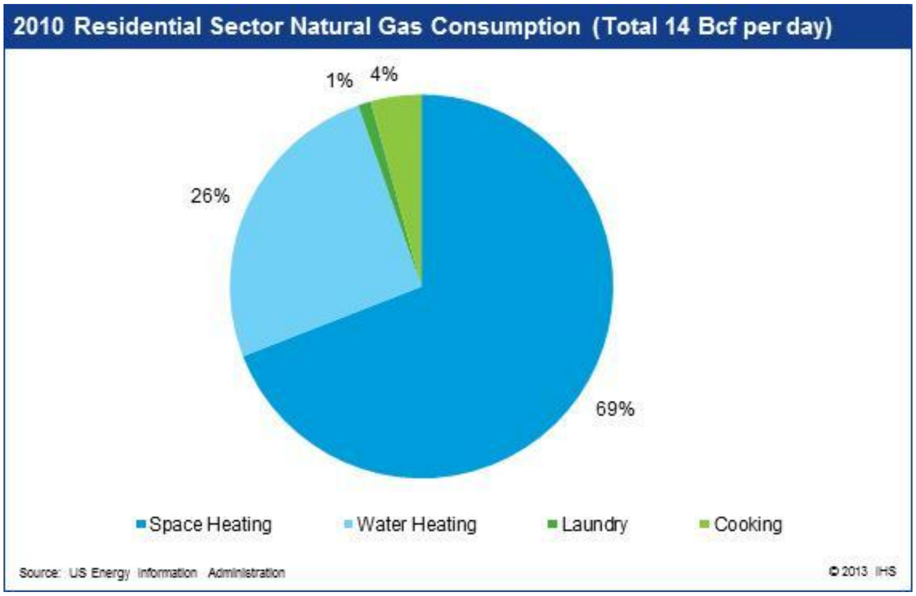
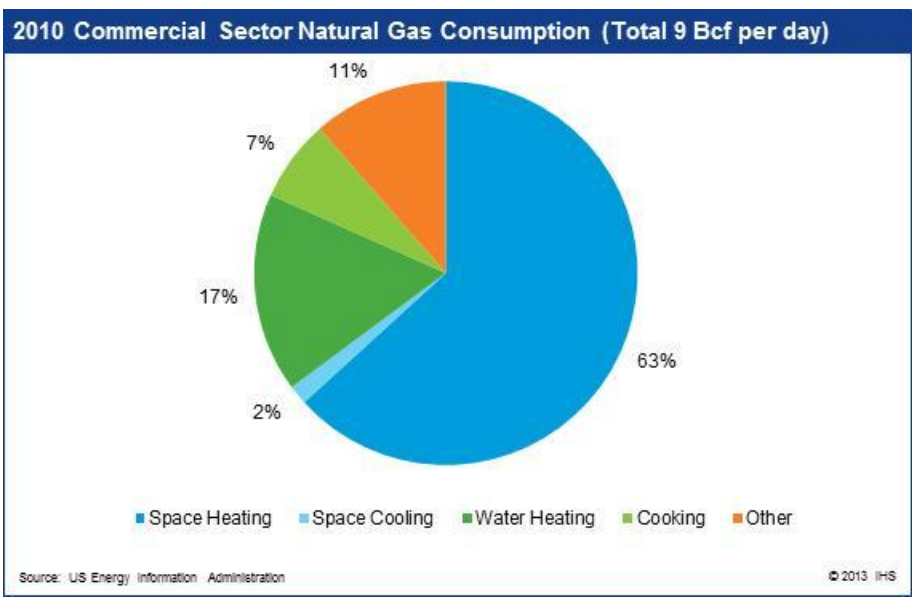


FIGURE IV.4



Natural gas provided two-thirds of all space and water heating and half of all cooking fuel in the residential sector in 2010 (see Table IV.1). Natural gas was even more dominant for these uses in the commercial sector, providing more than 70% of space and water heating and 89% of the fuel used for cooking.

TABLE IV.1

2010 Energy Consumption and Market Shares

Residential and Commercial Sectors

		Natural Gas	Electricity	Oil	Other	Total
Residential Sector						
Space Heat	TBtu	3,496	867	530	335	5,228
	%	67	17	10	6	100
Water Heat	TBtu	1,294	457	98	72	1,921
	%	67	24	5	4	100
Cooking	TBtu	216	183	0	30	429
	%	50	43	0	7	100
Other	TBtu	55	3,894	0	161	4,110
	%	1	95	0	4	100
Commercial Sector						
Space Heat	TBtu	1,647	394	225	63	2,329
	%	71	17	10	3	100
Water Heat	TBtu	438	119	27	0	584
	%	75	20	5	0	100
Cooking	TBtu	179	23	0	0	202
	%	89	11	0	0	100
Other	TBtu	1,023	4,143	264	196	5,626
	%	18	74	5	3	100

Source: US Department of Energy

TABLE IV.2

2009 Space Heating in US Homes
(million homes)

	Total US	Northeast	Midwest	South	West
Total Homes	**113.6**	**20.8**	**25.9**	**42.1**	**24.8**
Natural Gas	55.6	10.8	17.9	13.3	13.6
Electricity	38.1	2.4	4.6	24.2	7.0
Central Furnace	19.1	0.3	2.3	13.7	2.9
Heat Pump	9.8	0.4	0.6	7.5	1.3
Other Electric	9.3	1.7	1.6	3.0	2.9
Fuel Oil	6.9	5.7	0.5	0.6	0.1
Other	9.4	1.8	2.9	2.9	1.6
No Heating	3.5	Q	Q	1.0	2.4

Q: Data withheld either because the Relative Standard Error (RSE) was greater than 50 percent or fewer than 10 households were sampled.

Source: US Energy Information Administration

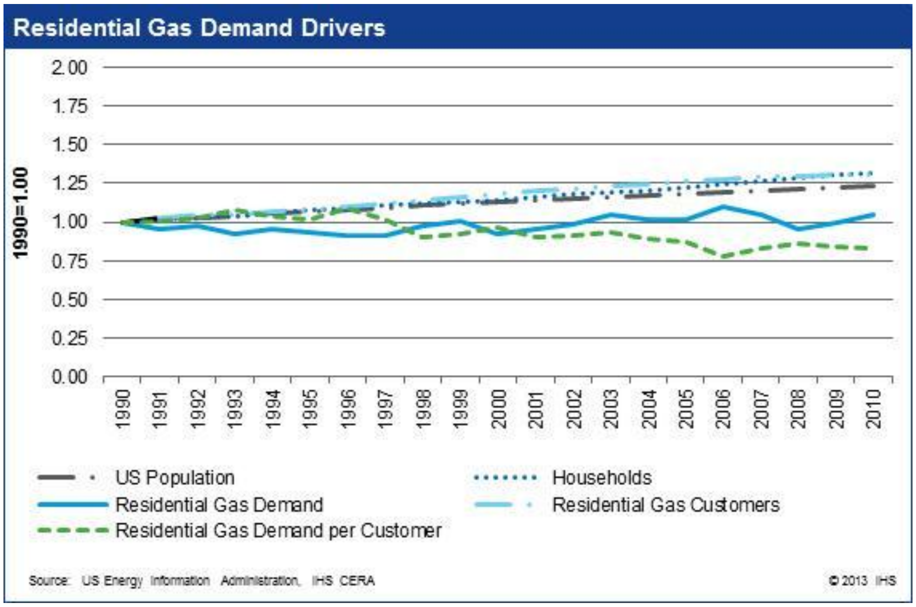
Drivers of residential natural gas demand

The primary drivers of residential natural gas demand are:

- Population
- Number and size of single family and multi-family households
- Natural gas appliance share of space heating, water heating, cooking and clothes dryer appliances
- Rate of residential energy efficiency gains measured by changes in residential natural gas consumption per residential customer

Simplistically, residential natural gas demand has been and is expected to remain relatively flat as continuing gains in energy efficiency offset growth in residential gas customers unless natural gas increases its share of residential energy requirements at the expense of oil or electricity (see Figure IV.5).

FIGURE IV.5



Population

US population growth is a function of births, deaths and immigration. The US population growth rate for the period 1990 to 2011 was 1.01%. For the period 2012 to 2035 it is expected to decline to 0.70%. All other things being equal, total household formations should grow at the same rate as population. However, there has been a long-term trend of fewer people per household. Since 1990 the number of persons per household has declined from 2.72 per household to 2.66 per household as of 2011 and is expected to decline further to 2.51 by 2035.[50] The number of residential gas customers is primarily a function of the competitiveness of natural gas to serve space heating needs. The percent of households receiving natural gas service peaked in 2007 at 57% and has declined to 56% in 2011.

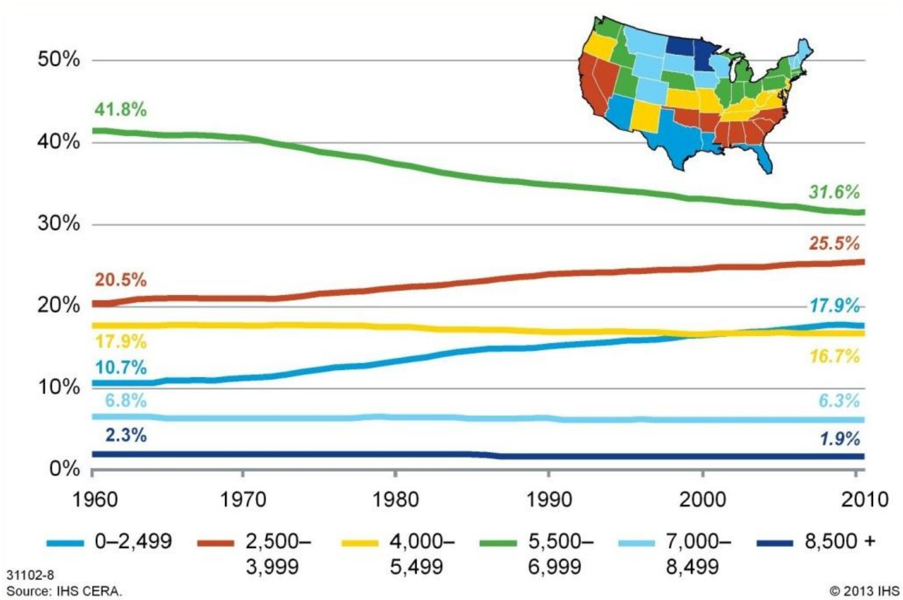
Where population and household growth occurs matters as the seasonal requirements for heating and cooling very significantly across the country. Between population growth and migration, most of the growth in households over the past few years has occurred in the South, and to a lesser extent in the West, both of which have fewer heating degree-days (HDDs) but more cooling degree-days (CDDs) than the national average (see Figure IV.6). The internal shift in population towards the west and south has reduced the overall US growth rate for heating services. In 1960, 31.2% of the US population lived in the warmest states, where annual HDDs averaged less than 4,000. By 2010, this share of the population had risen to 43.4%. In contrast, the share of the population living in colder states, with HDDs ranging from 4,000 to 6,999, declined from 59.7% of the population in 1960 to 48.3% in 2010. The share of the US population living in the coldest regions, where HDDs average more than 7,000, has also declined slightly from 9.1% in 1960 to 8.2% in 2010. Furthermore, the electric heat pump is very competitive with natural gas furnaces where most of the growth in households has occurred and is expected to continue to occur (see discussion below under "Operating costs of space heating systems"). As a consequence, electric heating increased its share of new single home heating systems from 26% in 2000 to 44% in 2010 before declining to 39% for 2012.[51]

[50] IHS Global Insight.

[51] US Department of Commerce.

FIGURE IV.6

Share of US Population by Heating Degree Day Range

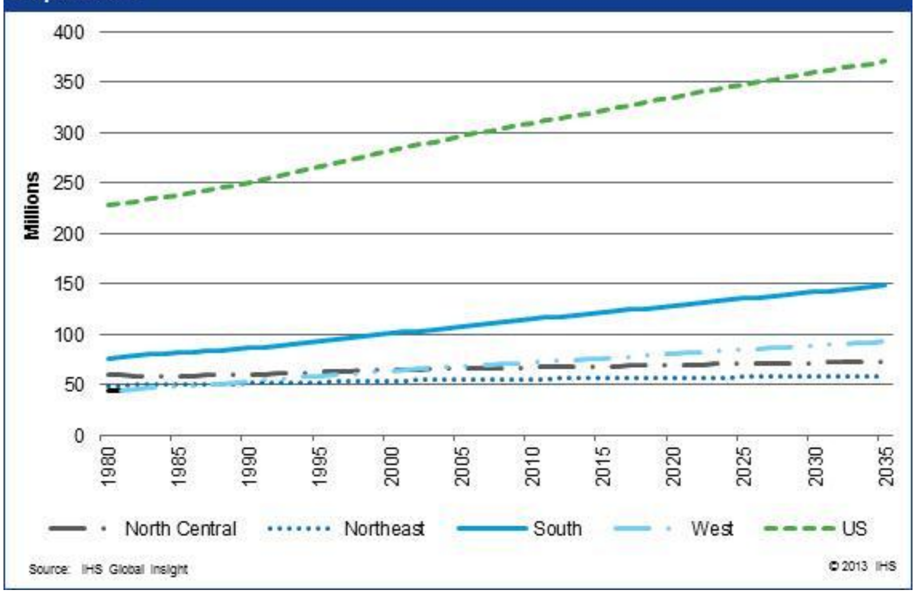


Source: http://www.eia.gov/todayinenergy/detail.cfm?id=8810

The shift in population away from colder regions is expected to continue as most of the US population growth is expected to occur in the South (see Figure IV.7)

FIGURE IV.7

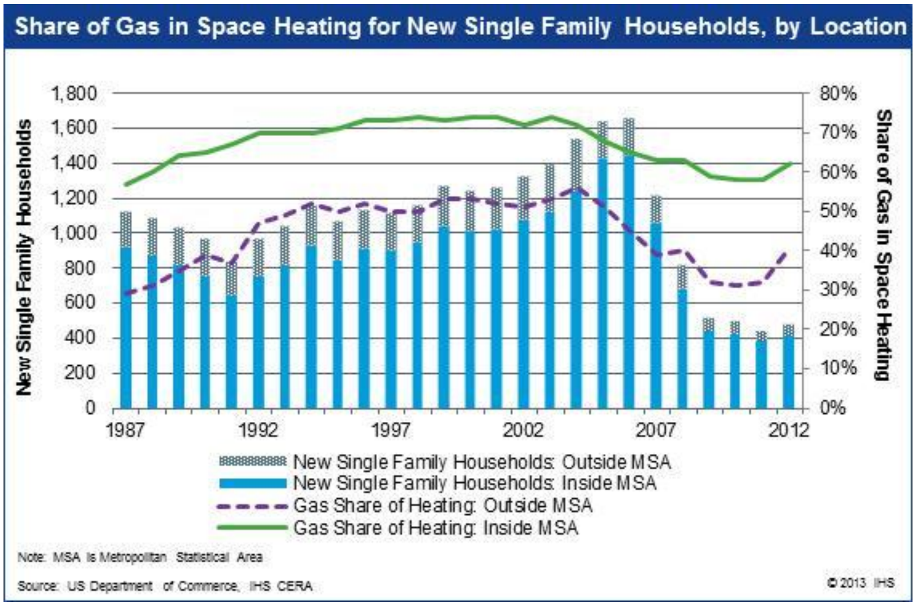
Population



Household formation

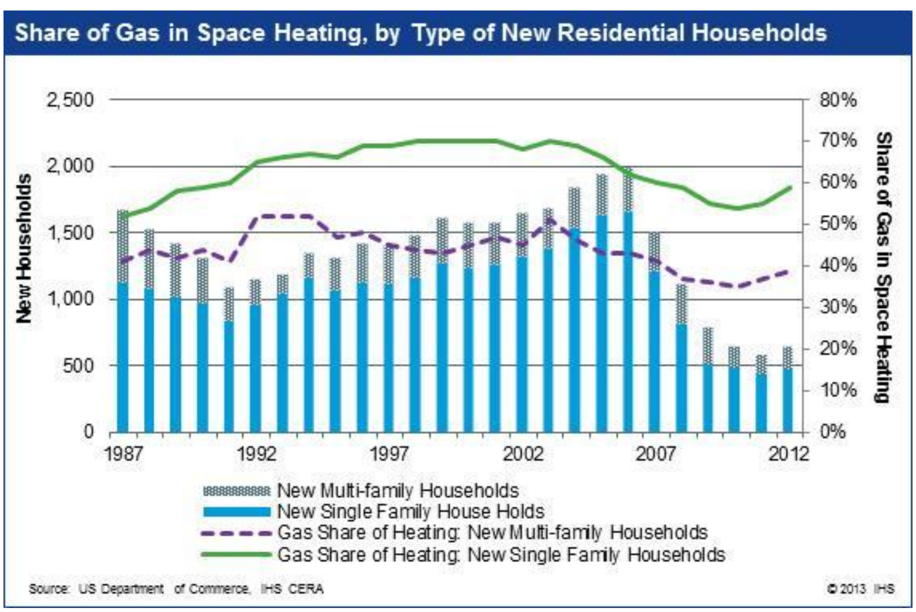
The trend has been for new household formation to occur inside Metropolitan Statistical Areas (MSAs) rather than outside them (see Figure IV.8). This trend is generally good for natural gas as there is a greater probability that gas distribution infrastructure already exists within MSAs. If not, the greater population density of MSAs should improve the economics of extending gas service to new households.

FIGURE IV.8



The type of new households, single family or multi-family, is also important as natural gas' share of heating is lower for multi-family units (see Figure IV.9). In multi-family units, with rare exception, electricity has outcompeted gas as the heating fuel choice for new units since the mid-1970s. By 2012 natural gas held only a 23% heating fuel market share for all new multifamily units, a modest increase from its 2000 share of 21%.

FIGURE IV.9



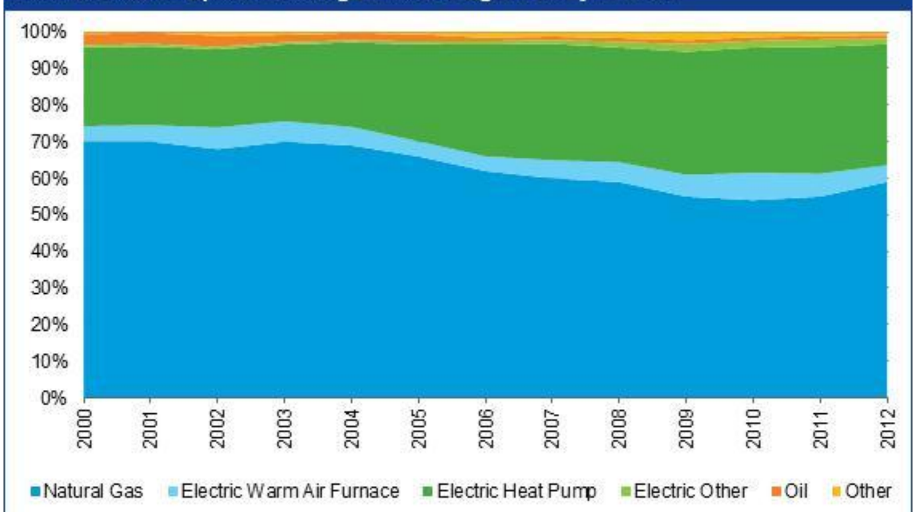
Gas' share of heating for new homes has been declining (see Figure IV.10). In terms of new construction, data from the US Department of Commerce show that the natural gas market share for space heating in new single-family homes increased steadily from 1978 (when the Natural Gas Policy Act provided for the gradual decontrol of wellhead gas prices) to 2000. Over this period, the proportion of new houses built with natural gas space heating increased from 37% to 70%. Beginning in 2000, however, demand for electric heat pumps grew faster than other residential heating applications. The share of new US single-family homes built with electric heating increased from 27% in 2000 to 39% in 2012, while natural gas's share declined from 70% to 59% during the same period (see Figure IV.10). However, there is wide variation from region to region:

- **Northeast**: From 2000 to 2012 gas heating share increased from 65% to 82% and electric heating share increased from 6% to 10%.
- **Midwest:** From 2000 to 2012 gas heating share decreased from 92% to 77% and electric heating share increased from 7% to 21%.
- **South:** From 2000 to 2012 gas heating share decreased from 50% to 37% and electric heating share increased from 50% to 62%.
- **West:** From 2000 to 2012 gas heating share decreased from 91% to 87% and electric heating share increased from 8% to 11%.

The most popular electric heating technology for new home construction has been the electric heat pump, which had about 23% share of all new single-family US homes in 1999 and grew to a 38% share in 2011. Again there is wide variation from region to region. For new single family homes built in 2012, electric heat pumps were installed in 8% of Northeast homes, 21% of Midwest homes, 62% of South homes, and 9% of West homes. Clearly, the use of natural gas for heating is facing its greatest challenge in the temperate South region, the region expected to have the highest growth in population (see Figure IV.7).

FIGURE IV.10

Fuel Shares of Space Heating in New Single Family Homes



Source: US Department of Commerce

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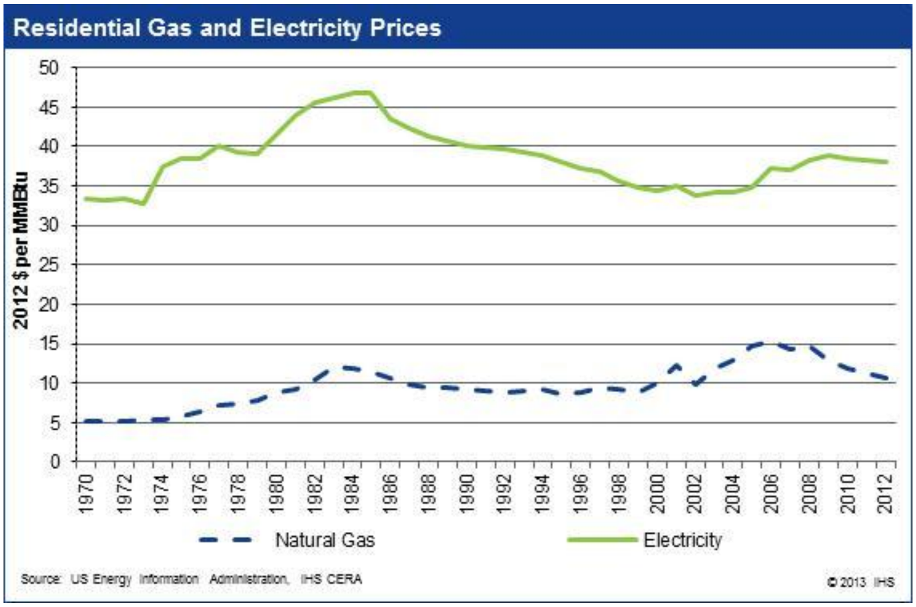
Technological improvements have substantially improved the efficiency of electric heat pumps. Electricity prices have declined significantly relative to gas prices in the past 40 years, although IHS CERA expects that trend to reverse soon. In the early 1970s, electricity prices were more than 6 times the gas price; by 2005 they were only about 2.5 times as high, but have since increased to over 3 times as high (see Figure IV.11).[52] Finally, builders and landlords generally prefer to install appliances with lower up front capital costs, even though they may have higher operating costs, as builders do not generally have to pay operating costs. For this reason, the builder/landlord preference usually favors the electric appliance over the gas one unless customers request gas.

FIGURE IV.11



Residential energy efficiency

In addition to growth in households and the number of households having natural gas service, the other major driver of residential natural gas demand is the rate of improvement in energy efficiency of residential gas appliances and thermal integrity of homes. As Figure IV.5 shows, residential gas demand per residential gas customer has declined steadily, in part a result of gas LDC energy efficiency programs. The growth in the number of residential gas customers has effectively been offset by an increase in residential natural gas efficiency. As a consequence, residential natural gas demand has been relatively flat. Chapter V contains further discussion of energy efficiency issues.

Outlook for residential natural gas demand

Most forecasters, including IHS CERA, expect little, if any, growth in residential natural gas demand. However, as discussed below, if natural gas can increase its share of residential fuel through conversions from fuel oil or electricity for both single family and multi-family households, improvement in the competitiveness of natural gas furnaces versus electric heat pumps, significant installation of home refueling units for natural gas vehicles, or from transformational breakthroughs in microCHP units or fuel cells, then residential natural gas demand could be higher. Realizing these opportunities will be quite challenging and may require a rethinking of policies and programs by policy makers, PUCs and gas LDCs.

[52] Declining electricity prices over this period corresponded to an increase in low-cost coal-fired power generation.

Opportunities to increase residential natural gas demand

This section discusses major opportunities to increase residential natural gas demand and the associated challenges.

Inter-fuel competition

One way to expand natural gas use in core gas LDC markets is to convert existing electric or oil appliances to natural gas appliances. This will mean increased inter-fuel competition and with it will come some regulatory issues that will need to be addressed. In particular, PUCs will need to assure that there is a level competitive playing field for all forms of energy, but especially between gas and electricity. One critical role for PUCs will be to address gas and electric competition for combination utilities, or companies that distribute both gas and electricity. Most companies are reluctant to cannibalize their markets by promoting competition between affiliates. However, without such competition society may not gain the benefits of lower total energy usage and lower emissions from conversions to natural gas. (See Chapter V for a more in depth discussion of total energy and emissions benefits.) As of 2011, combination companies had total gas deliveries of 23.6 Bcf per day to 44 million gas customers, a very substantial portion of all gas LDC deliveries and customers. PUCs will need to assure that expansions of gas LDC systems do not tilt the playing field against electric and oil competitors by having existing customers (ratepayers) subsidize expansions.

Another conversion issue to be addressed is a seeming policy bias against promoting increased use of any fossil fuel. Some parties are concerned that any increased use of fossil fuels will ultimately lead to greater emissions, especially greenhouse gas emissions, even if greater of use of natural gas reduces such emissions for the next few years. Furthermore, there seems to be a policy bias favoring electricity under the premise that electricity will become increasingly “green” owing to a shift to renewable generation. Gas LDCs need to educate policy makers on the “green” benefits from a shift to natural gas until cost effective technologies, other than dispatchable gas-fired generation, are developed to balance intraday variations in electricity demand and the intermittency of renewable generation.

Conversion from oil and electricity to natural gas

One way to expand natural gas use in core gas LDC markets is to replace existing electric or oil appliances with natural gas appliances. Depending on the region, a gas furnace or water heater can have significant cost and efficiency advantages over a comparable oil or electric appliance. However, where a new service line or an extension of a distribution mainline is required, the high up front costs may deter customers from converting and, in some cases, the difficulty in getting regulatory approvals for an expansion may slow the rate of conversions.

An estimated 12 million households use natural gas for water heat and/or cooking, but not for space heating. Many of these households might be candidates for converting to gas for space heating. This would add to the volume of gas delivered by the gas LDC, but as previously discussed it would not necessarily add to the gas LDC's rate base and any benefits to the LDC are likely to be temporary.

In communities with existing natural gas distribution mains, hooking up new customers can be simply a matter of extending a service pipe from the distribution main to the house. Extending service to new communities will involve building out an entire distribution infrastructure. (See Chapter VI for a more in-depth discussion of issues surrounding extension of service to new customers.) But when natural gas service can be designed into the infrastructure supporting new construction, homes and commercial buildings can be built with gas appliances that will operate at higher overall energy efficiency and at lower cost than many competing technologies. As discussed further below, the capital and operating costs of gas furnaces and water heaters are in most cases lower than those of their electric counterparts. Furthermore, capital and operating costs are generally lower for systems that include gas for space and water heating together with electric central air conditioning than for systems that rely more heavily on electric technologies.

Oil-to-gas conversions

One area where gas has enjoyed considerable success in expanding into existing communities has been in replacing oil for space and water heating. As of 2009, 6.9 million US homes used oil for space heating.[53] In the Northeast, 5.7 million homes use oil for heating, despite retail natural gas prices that are less than one half those of retail prices for fuel oil. On average each residential gas customer in the Northeast used 85 Mcf per year in 2011.[54] Many gas LDCs have programs and incentives to support conversion from oil to efficient natural gas equipment. The City of New York passed a law in 2011 that mandates the phase-out of #4 and #6 fuel oil as a heating fuel source for buildings (see the box "Oil-to-gas conversions in New York City").

Residential and commercial oil-to-gas conversions represent a strong growth opportunity for gas LDCs in the Northeast because heating oil use in New York and the six New England states is much higher than the national average. For example, oil provides 10% of home heating nationwide, but 76% in Maine and 30% in New York state.[55] In the New England regional market oil has a 24% market share. Pennsylvania and New Jersey rely on heating oil for 20% and 9% of home heating, respectively. Fuel oil is also used to heat water in 3.5 million residences in the Northeast. By comparison, natural gas has a 67% share of home heating nationwide, but only 40% in New England (7% in Maine) and 57% in New York State.

Oil-to-gas conversions have been steadily increasing, and they could go higher. An American Gas Association analysis, based on data from the American Community Survey and the US Census Bureau, finds that more than 500,000 housing units in the US Northeast switched to natural gas space heating between 2000 and 2010 or about 50,000 per year.[56] At that pace it would take until 2123 to convert all oil heating homes to natural gas heating. Clearly, accelerating the pace of conversions is an opportunity for Northeast gas LDCs to increase their markets.

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[53] US Energy Information Administration, Office of Energy Consumption and Efficiency Statistics, Forms EIA-457 A and C of *2009 Residential Energy Consumption Survey*.

[54] US Energy Information Administration, *Natural Gas Annual 2011*.

[55] US Energy Information Administration, *Residential Energy Consumption Survey, 2009*.

[56] http://www.aga.org/Newsroom/news-releases/2013/Pages/More-than-Half-a-Million-Northeast-Homes-Switched-to-Natural-Gas-Heat-from-2000-2010.aspx, accessed June 27, 2013.

Some gas LDCs have developed programs to accelerate conversions. According to the Northeast Gas Association, NStar's Massachusetts residential conversions in 2012 were five times higher than the previous eight-year average.[57] National Grid had nearly 11,600 residential customers in Massachusetts switch to gas in the 12 months ending March 31, 2012.[58] New Jersey Natural Gas reported over 3,800 new customers converting from other fuels in fiscal year 2012, a 13% increase over the previous fiscal year.[59] At this rate about one-fifth of all oil-heated homes could be converted to natural gas by 2035. With tax credits, other incentives, and mandates such as those in New York City, conversions could rise to as high as one-third of all oil heated homes. This represents a potential 0.4 Bcf per day of incremental residential natural gas demand. Commercial conversions under similar programs could add another 0.2 Bcf per day of potential commercial natural gas demand. Conversion of ***all*** residential and commercial oil heat to natural gas in the Northeast would add 1.5 Bcf per day, an increase of 30% from 2011 Northeast levels.

Natural gas conversions and new installations in the Northeast have accelerated in the past few years thanks to new natural gas infrastructure and the significant operating cost advantage of natural gas compared with oil. Replacement of fuel oil with natural gas is easier in urban areas with higher density of existing distribution and pipeline networks, and minimal or no connection fees required to connect new customers. In the case of New York City, a governmental mandate and low cost financing for conversion from fuel oil to natural gas will drive an increase in gas demand (see the box "Oil-to-gas conversions in New York City"). In areas with little existing distribution or pipeline facilities, often areas with low population density, regulatory support and the use of "anchor tenants" may be needed to expand a distribution network to serve new converting customers (see the box, "Oil-to-gas conversions in Maine"). In terms of heating fuel for construction of new single family homes, natural gas is already favored in the Northeast region. The share of gas in new multifamily homes in this region has increased from 65% in 2000 to 82% in 2012. Conversion from oil to natural gas is a short- to medium-term opportunity, but also a regional one limited primarily to the Northeast.

[57]Northeast Gas Association, *Statistical Guide to the Northeast US Natural Gas Industry, 2012*.

[58] *The Patriot Ledger*, 3 June 2012.

[59] *New Jersey Resources*, FY 2012 Earnings Release.

Oil-to-gas conversions in New York City

PlaNYC, a collaborative effort of 25 agencies to work toward a better, greener future for New York City, is an important driver of the expansion of natural gas service in the largest metropolitan area in the United States. Launched in 2007 and updated in 2011, with more than 400 specific milestones by December 31, 2013, PlaNYC aims, among other things, to make New York City's air the cleanest among all other major US cities. It outlines strategies to reduce emissions from buildings, on-road vehicles and other transportation sources.

Based on estimates that emissions from about 10,000 buildings burning residual fuel oil (No. 6 and No. 4) contributed very high levels of particulate matter, New York City mandated the conversion of residual fuel oil boilers in apartment buildings to either distillate fuel oil or natural gas. In July 2010, a local law was passed requiring fuel oil to have no more than 1,500 parts per million of sulphur and contain 2% biodiesel starting in October 2012. This placed a high cost on using residual fuel oil. In 2011, the New York City Department of Environmental Protection issued regulations mandating the phase-out of No. 6 residual fuel oil for heating by 2015 and No. 4 residual fuel oil for heating by 2030. All new boiler or burner installations must utilize cleaner fuels, which include natural gas, ultra-low-sulphur No. 2 oil, biodiesel, or district steam. In June 2012, the city, through the New York City Energy Efficiency Corporation, partnered with major banks, energy providers, and environmental groups to provide $100 million in low cost financing and technical assistance to buildings required to move to cleaner heating fuels. New York City reports that more than 1,900 residential buildings had switched away from heating oil by early 2013, with a significant number choosing natural gas.

Availability of natural gas supply to New York City is currently constrained in winter months by limited pipeline capacity, and any expansion of winter demand must be accompanied by an equivalent expansion of pipeline capacity. Texas Eastern Gas Transmission Company filed for approval to build an 800 MMcf per day, 16-mile extension from New Jersey into Manhattan. This expansion is necessary to meet the incremental demand from converting existing fuel oil customers in Consolidated Edison Company's New York City territory. It will also interconnect with Public Service Electric and Gas Company in Bayonne and Jersey City, New Jersey. The project received a significant amount of opposition from politicians and environmental groups, although it received FERC approval in May 2012 and was placed into service in November 2013. Transcontinental Gas Pipe Line Corporation (Transco) is working also on the small 3.2 mile Rockaway lateral pipeline in New York to create an additional delivery point from the existing Transco system into National Grid's distribution network, enhancing service reliability and serving growth in the region.

Oil-to-gas conversions in Maine

As of 2009, Maine had 20,806 residential, 8,815 commercial, and 85 industrial natural gas customers, achieving only a 4% share of space heating, after a decade's operation of the Maritimes & Northeast Pipeline (M&NE). Maine heats 76% of its homes with oil, with a gas demand potential of 200 MMcf per day from converting the oil-heating load to gas, but lacks distribution infrastructure.[60] Existing gas LDCs include Unitil (the former Northern Utilities), serving Portland; Bangor Natural Gas, serving Bangor; Maine Natural Gas, serving south-central Maine; and Kennebec Valley Gas (KVG, sold to Summit Gas, a subsidiary of Colorado-based Summit Utilities, in 2012), which intends to serve the greater Augusta area. These utilities are all seeking to expand their customer bases, spurred by favorable economics but limited by the low density of prospective customers.

By 2011, Maine had expanded its natural gas service to 22,461 residential, 9,681 commercial and 101 industrial customers. Anecdotal evidence suggests that fuel oil consumption by late 2012 had fallen by as much as 40-45%, although some of the decline was undoubtedly due to the uncharacteristically warm weather. Interest in switching to gas is very strong and all Maine gas LDCs are laying down plans for mains expansions and developing programs to assist future customers with conversion expenses. Maine Natural Gas and Summit Gas have proposals to extend their service territories by building the incremental cost into the rate structure without requiring any up front fees and the former is planning to cover half of the conversion expenses for new residential and commercial customers.

New utilities, such as Summit, would serve areas such as central Maine from M&NE. Success for these utilities will require anchor tenants, state and local support through tax incentive financing or loan guarantees, and customer participation through contributions in aid of construction. Municipal utilities could also be formed using state bonding authority.

Natural gas versus electricity for residential space and water heating

In the residential and commercial sectors, it is primarily natural gas and electricity that compete for space and water heating as well as cooking. Capital costs, operating costs, efficiency, and weather all play a role in the competition between electric and gas appliances, with results very much dependent upon regional characteristics. This section focuses on the cost of various configurations for space heating and cooling and water heating. Cost is defined as the sum of capital costs, excluding customer installation and gas connection costs, and the present value of operating costs for fifteen years using a discount rate of 10%. Operating costs were based on required regional energy outputs for space heating and cooling appliances which is a function of temperature, energy outputs for water heating, energy efficiency of appliances, and 2012-35 average projected residential prices for natural gas and electricity from Figure IV.12

Over the last few years electric heat pumps have become a major space heating competitor for natural gas. Since 2000 electric heat pumps have increased their share of new single family home construction from 23% to 38%, however, over 80% of the electric heat pumps were added in the South, a more temperate region.[61] Although electric heat pumps have been favored for new home construction in recent years, only one quarter of all electrically heated homes have a heat pump (see Table IV.2). The majority are heated by less efficient electric central air furnaces that use resistance heating, or by electric resistance baseboard

[60]US Energy Information Administration, *Residential Energy Consumption Survey, 2009.*

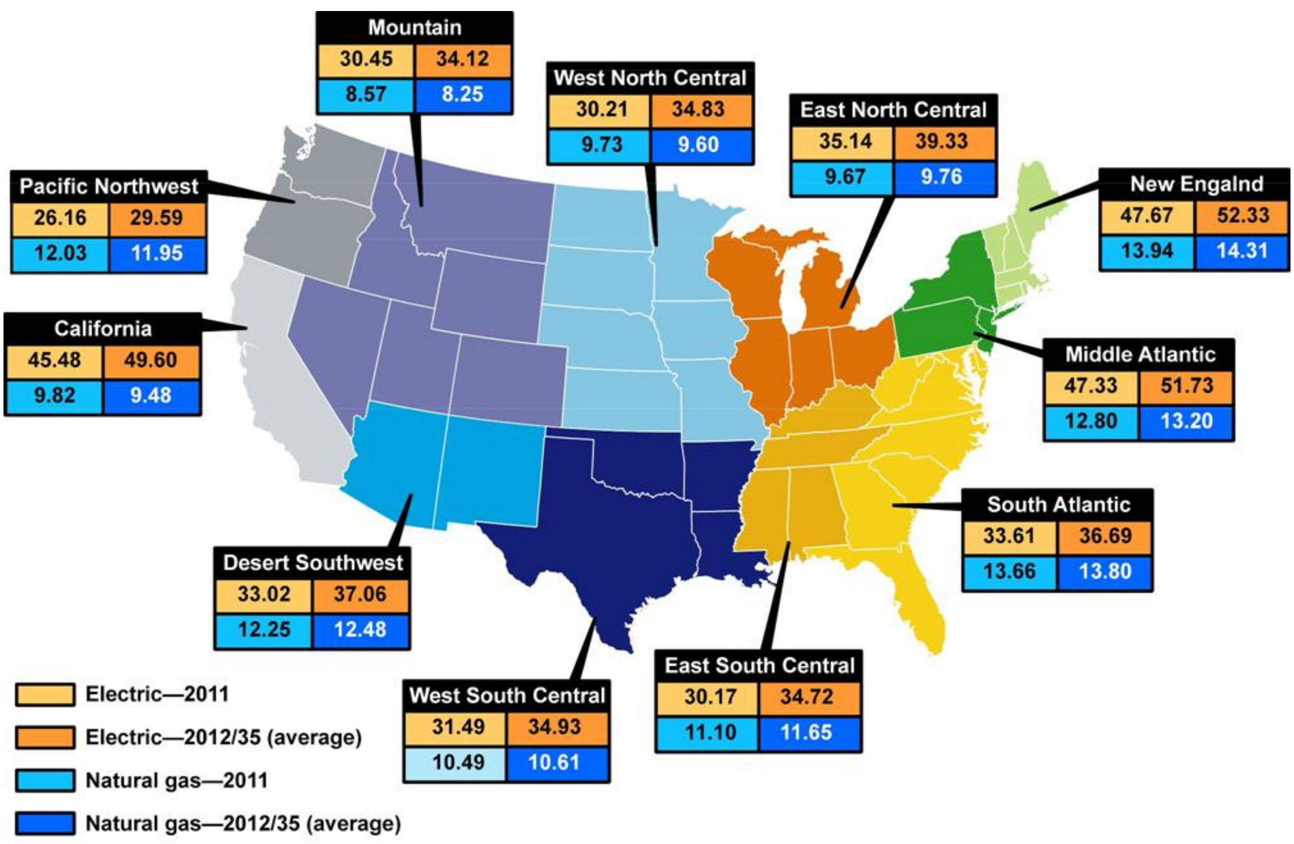
[61] US Census Bureau, *American Housing Survey 2012*.

units. Even homes with an electric heat pump generally use electric resistance heat as back-up on cold days when heat pump technology is insufficient to maintain a comfortable indoor temperature.

With natural gas prices expected to remain low for the long term compared to electricity prices, gas is well positioned to make inroads vis-à-vis electricity in many regions, especially against less efficient resistance heating, whether from central air furnaces or baseboard heating. For 2011, the ratio of residential electric retail prices to residential natural gas prices ranged from a low of 2.2 in the Pacific Northwest to a high of 3.7 in the Middle Atlantic. The higher the ratio to gas prices to electric prices, the easier for natural gas to displace electricity. The cost competitiveness of natural gas space heating versus electric heat pumps should improve as the spread between residential electric and natural gas prices is expected to increase (see Figure IV.12). One of the main reasons why residential electric prices are substantially higher than residential natural gas prices is that residential electric prices include the substantial generating cost of converting natural gas, coal, oil and nuclear fuel into electricity. Residential gas and electric prices reflect full fuel-cycle costs, as discussed in Chapter V. The ratio of average projected electric residential prices to average projected residential natural gas prices for 2012-35 ranges from a low of 2.5 for the Pacific Northwest to a high of 5.2 for California. However, in some markets, especially in more temperate ones, conversions from electric resistance heating might be to electric heat pumps rather than to natural gas furnaces.

FIGURE IV.12

Regional Residential Prices – Natural Gas and Electricity (constant 2012$ per MMBtu)



Source: IHS CERA.
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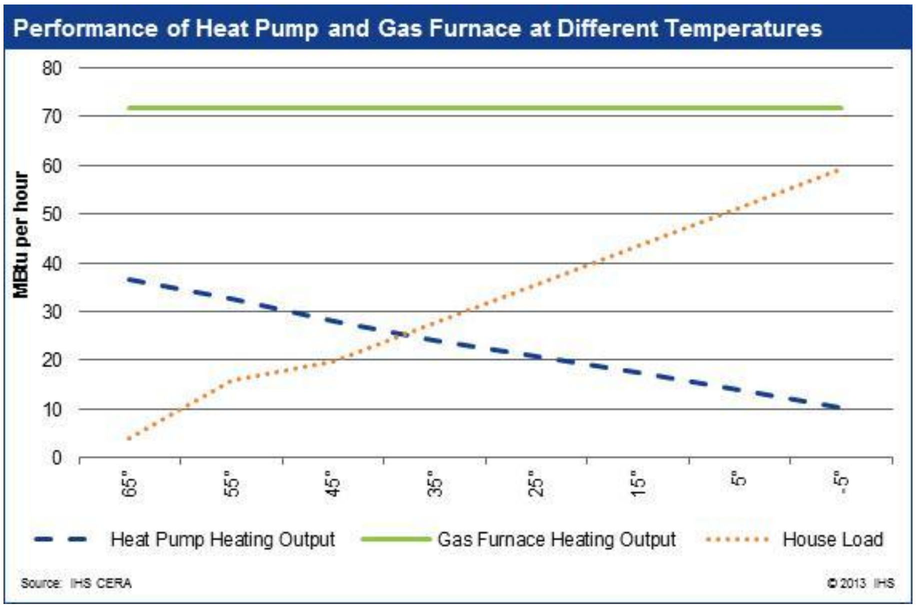
Operating costs of space heating systems

Operating costs of heating systems reflect energy prices, weather and appliance efficiency. Weather patterns cause great variation in operating costs, as heat pumps become less efficient as temperature drops (see Figure IV.13). If temperatures fall below a certain level, electric heat pumps revert to less efficient back-up heating to compensate for insufficient heating capacity. Where the back-up heat is provided by electric resistance systems, considerable efficiency is sacrificed in terms of primary energy losses.

FIGURE IV.13



For the northern United States, natural gas furnaces have a significant advantage over electric heat pumps and thus dominate consumer choice. Generally speaking, natural gas furnaces have a huge economic advantage over heat pumps at low temperatures but one that varies by region depending on local electric and natural gas retail rates.

Because of regional variations in temperature and energy prices, the operating costs of natural gas vis-à-vis electricity for space heating vary considerably across regions. When considering energy prices, in regions with very high electricity rates, such as California, a natural gas furnace will tend to be more cost-effective than in regions with lower electricity rates. When considering regional climates, a natural gas furnace will have an advantage in cooler climates where the heat pump is less effective and requires more back-up heat.

Using regional residential price projections for natural gas and electricity for 2012-35, IHS CERA has calculated regional breakeven temperatures below which the operating costs of the gas furnace are less than those for the electric heat pump. Then we have calculated the number of days when temperatures are expected to be below the breakeven temperature for the region, based on daily temperatures in 2011 and 2012 for a representative city in each region. The results are given in Table IV.3 and illustrated in Figure IV.14, where the size of the circle represents the number of days per year when temperatures are anticipated to favor natural gas heat.

For example, the East North Central region, where future electric prices are projected to average $38.64 per MMBtu, more than 4 times the average future residential gas price of $9.59 per MMBtu, has a breakeven temperature of 53° F. On days when the temperature falls below 53° F in this region, a gas furnace will be cheaper to operate than an electric heat pump. Based on the weather in Chicago (the representative city for this region) in 2011-12 there were 185 days per year with average temperatures below 53° F. Therefore, the gas furnace would have lower operating costs than the electric heat pump more than half of the year in the East North Central region. For the South Atlantic region, in contrast, with lower electricity prices, the breakeven temperature is 20° F and, based on daily temperatures for the representative city of Atlanta, there were no days with an average daily temperature this low in 2011 or 2012.

TABLE IV.3

Comparison of Regional Natural Gas Furnace and Electric Heat Pump Performance Characteristics

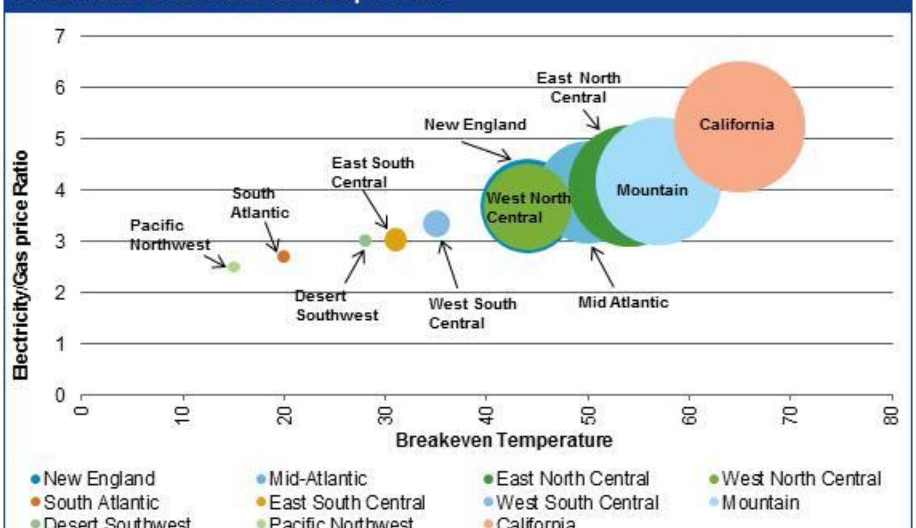
Regional Comparison (in $2012)

Natural Gas Favored Regions	United States	New England	Middle Atlantic	East North Central	West North Central	Mountain	California
Electricity Price (2012 $/MMBtu)	38.8	52.3	51.7	39.3	34.8	34.1	49.6
Natural Gas Price (2012 $/MMBtu)	11.1	14.3	13.2	9.8	9.6	8.3	9.5
Breakeven Temperature (Degree Farenheit)	40.0	44.0	50.0	53.0	43.0	56.0	65.0
Days Temperature Below Breakeven (Days per Year)		114.0	133.0	185.0	80.0	202.0	220.0
Representative City		Boston	New York	Chicago	St. Louis	Salt Lake City	Sacramento
Electric Heat Pump Favored Regions		**South Atlantic**	**East South Central**	**West South Central**	**Desert Southwest**	**Pacific Northwest**	
Electricity Price (2012 $/mmBtu)		36.7	34.7	34.9	37.1	29.6	
Natural Gas Price (2012 $/mmBtu)		13.8	11.6	10.6	12.5	11.9	
Breakeven Temperature (Degree Farenheit)		20.0	32.0	34.0	32.0	15.0	
Days Temperature Below Breakeven (Days per Year)		0.0	8.0	9.0	0.0	0.0	
Representative City		Atlanta	Memphis	Dallas	Phoenix	Seattle	

Source: National Oceanographic and Atmospheric Administration (NOAA), IHS CERA

FIGURE IV.14

Price Ratio to Breakeven Temperature



Source: National Oceanic and Atmospheric Administration(NOAA), IHS CERA © 2013 IHS

These calculations reveal a sharp divide between north and south, and illustrate why electric heat pumps have gained a large share of the southern US heating market while natural gas furnaces dominate the northern United States.

- Northern tier regions have from 80 to 202 days a year when electric heat pumps would be more costly to operate than gas furnaces. For most of these days, electric heat pumps would also fail to heat the home to a satisfactory level. The 2012-35 average ratios of projected residential electric prices to residential natural gas prices are expected to range from 3.6 to 4.1 in these regions.

- For southern regions and the Pacific Northwest, a combination of mild temperatures and lower cost electricity give electric heat pumps an operating cost advantage on all but a few days each year. The 2012-35 projected ratios of residential electric prices to residential natural gas prices are expected to range from 2.5 to 3.3 in these regions.

- For much of California, very high electricity costs and low natural gas prices provide a very economic opportunity for expansion of natural gas service. In Sacramento, for example, gas furnaces would be less expensive to operate than electric heat pumps for 220 days each year. In southern California, there are few days requiring space heating. The 2012-35 average projected ratio of residential electric prices to residential natural gas prices in California is 5.2, the highest of any region.

IHS CERA's analysis does not include a comparison to a natural gas engine heat pump as to date very few have been installed in the United States (see the box "The natural gas engine heat pump"). Recent field tests suggest that more research and development is needed to make this a cost-effective competitor to the electric heat pump.

The natural gas engine heat pump

Eventually the gas heat pump could facilitate the penetration of natural gas into US markets now dominated by electric heat pumps. Natural gas heat pumps provide a site efficiency of up to 140% of input energy for heating and can also produce more than 100% of input energy for cooling. While these site efficiencies are less than those of electric heat pumps, full fuel-cycle efficiencies are greater (see Figure IV.15). The efficiency of the gas engine heat pump can be improved by capturing the waste heat from the gas engine and using it to heat water or to supplement indoor heat. With the price of natural gas at about one third that of electricity, operating costs will likely be lower than for electric heat pumps. Finally a gas heat pump that provides cooling service will reduce peak electric demand thus saving the electric utility the expense of peak generation capacity.

One Japanese company has installed more than 600,000 gas engine heat pumps worldwide. This company has formed a US subsidiary and is engaged in pilot projects with the DOE, Oak Ridge Laboratory and several gas utilities.

- Pilot projects at the Department of Defense show operating cost savings averaging more than $1,500 per year for commercial scale installations of gas engine heat pumps with a high level of reliability. The pilot project was run by the Army Corp of Engineers and showed an average efficiency of 118% for the six installations at Air Force bases.

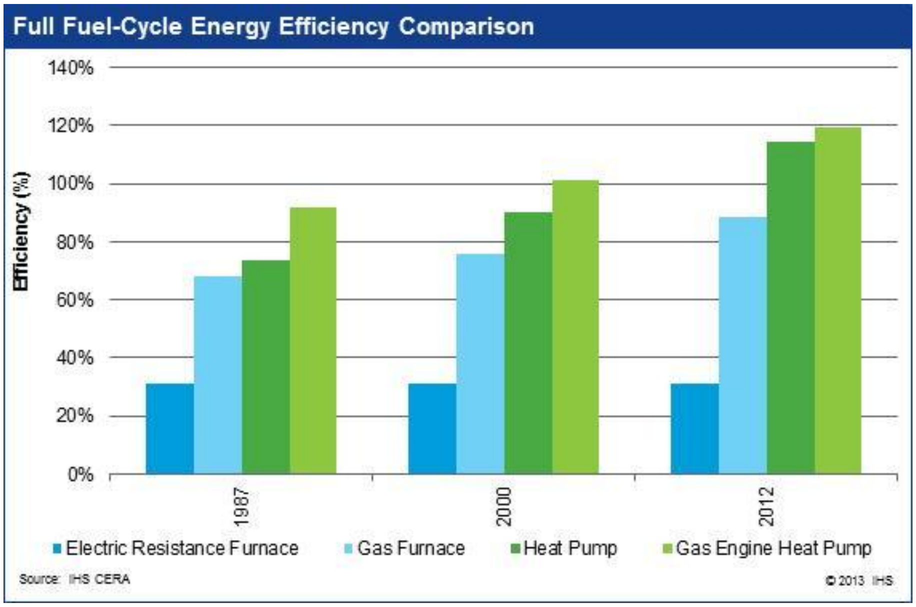
- Atmos Energy and the City of Plano, Texas ran a yearlong experiment with a gas heat pump in 2012. The Plano fire department installed a gas engine heat pump and an electric heat pump at two similar fire stations and ran a comparison which indicated savings of $2,200 per year and a payback period of seven years. Part of the savings came from reducing electricity demand charges by 18 kilowatts (kW).

- Oak Ridge National Laboratory has shown that gas heat pumps have a full-cycle heating efficiency potential greater than their electric driven counterparts that is slightly offset by a small decrease in cooling mode efficiency, with the overall result that the gas heat pump consumes less primary energy than the electric heat pump.

- The use of natural gas for cooling results in a direct reduction in peak electricity requirements while improving the system utilization of natural gas distribution facilities. For commercial installations, natural gas heat pumps reduce the electric demand charges which are often $5 to $10 per kW per month, equivalent to a $1,200 to $2,400 annual savings and representative of the incremental cost electric cooling places on the energy system.

However, currently gas engine heat pumps have higher initial cost and more frequent maintenance than electric heat pumps. The life of a natural gas engine for a heat pump can be 30,000 hours or only about eight to ten years at a normal operating rate for heating and cooling—a serious disadvantage if the payback period is as long as seven years, as in the Plano Texas experience. Gas heat pumps need to be sized such that they operate for long periods thereby avoiding frequent starts and stops. More research and development needs to be done to advance the commerciality of gas heat pumps.

FIGURE IV.15



Costs for space heating, space cooling, and water heating

When the analysis is extended beyond space heating to include air conditioning and water heating, and when capital costs are also considered, rather than just operating costs, most regions of the country are shown to enjoy savings with some use of natural gas, compared to relying exclusively on electricity for these applications. Four cases are considered for this analysis:

- **The natural gas heating/electric air conditioning system** uses gas for space and water heating and electricity for air conditioning.

- **The electric heat pump/gas furnace backup system** The heat pump is used for all heating above 40° F and for a portion of the heating requirements below 40° F. This system uses the least expensive form of water heating (gas or electric) depending on local prices.

- **The all-electric heat pump system** uses an electric heat pump for space heat and air conditioning, with electric resistance heat for backup on cold days. A hybrid heat pump electric water heater is used.

- **The all-electric resistance heat system** uses an electric furnace for heat, an electric central air conditioner, and electric water heat.

An average home size of 2,000 square feet was assumed for calculating heating and cooling requirements. Capital costs were derived from a comparison of prices offered by a particular manufacturer or retailer for competing gas and electric appliances. This cost analysis does not include installation costs, as data were not available on region-specific consumer installation and connection costs for these appliances. Installation costs are analyzed separately in the following section. Appliance sizes were chosen for each region based on manufacturer recommendations or the representative city in each region.[62] A discount rate of 10% and a 15-year appliance life were used. As in the previous section, operating costs were calculated using IHS CERA's regional price projections for 2012-35, expressed in constant 2012 dollars. The analysis used the daily average temperatures for representative cities in each region during 2011 and 2012. Since temperatures have been slightly higher in recent years, this provides a relevant heating and cooling requirement to consider when purchasing appliances.

The results of the analysis are shown in Table IV.4. Electric resistance heating systems are far more costly in all regions than competing systems. Electric heat pumps with electric resistance heat for back-up are also more costly than systems with natural gas back-up. Capital and operating costs are significantly lower in most regions when natural gas is used for space and water heat, with electric air conditioning. The average present values of savings over fifteen years for a gas-heated home relative to an all-electric home across all 11 regions is $5,731.

These results reflect very efficient gas and electric appliances within a well-insulated home under weather patterns such as existed in 2011 and 2012 – relatively warm years. Alternative assumptions of colder weather, less efficient appliances, and high heat requirements would accentuate the cost advantage of natural gas. In both cases, the results would support expanded programs of assistance to low income households either to convert to gas or to improve their efficiency of gas use.

TABLE IV.4

Present Value of Capital and Operating Costs for Heating, Cooling, and Hot Water

Natural Gas vs. Electric

Region	Natural Gas Heating/Electric Air Conditioning System	Electric Heat Pump/Gas Furnace Backup System	All-Electric Heat Pump System	All-Electric Resistance Heat System
New England	$15,291	$20,203	$25,056	$31,506
East North Central	$13,212	$18,170	$23,260	$27,687
Middle Atlantic	$14,143	$17,646	$21,079	$27,854
Mountain	$12,042	$16,114	$20,175	$24,065
West North Central	$11,564	$12,701	$13,554	$20,459
Pacific Northwest	$10,080	$13,271	$12,510	$20,444
East South Central	$11,314	$11,925	$13,244	$17,275
West South Central	$10,852	$11,371	$12,692	$15,276
California	$9,675	$10,557	$11,871	$20,890
South Atlantic	$11,643	$11,615	$12,334	$15,656
Desert Southwest	$11,229	$11,371	$11,521	$13,674

Note: Costs Include Present Value of Capital Costs and Operating Costs over 15 Years at a Discount Rate of 10%.

Souce: IHS CERA

[62] Appliance manufacturers recommend different appliance size and models for each of five climate zones, which do not correspond to the census regions for which energy price projections are available. However, the representative cities whose climate characteristics are used for this analysis are the same for both the climate zones and census regions.

Installation and connection costs

The cost comparisons of the preceding sections do not take into account installation costs, which can affect the cost of replacing an existing electric appliance with a natural gas one. The case of an electric furnace is illustrative. Although significant capital and operating cost savings can be achieved by replacing an electric furnace with a natural gas furnace, installation costs can offset other cost benefits. Although every retrofit will be unique, consumer installation costs may include:

- Removal of existing appliance
- Adapting existing duct work, which may be complicated if the existing system includes an older central air conditioner with incompatible fittings for the new furnace. System designs change often, so the existing air conditioner may have to be replaced.
- In the case of baseboard electric heat, new ductwork will be required for the central air natural gas furnace.
- Services of a licensed plumber will be required to add internal gas lines from the meter to the appliances within the home. A licensed electrician will be required to add any needed electric lines.
- The gas furnace will require a chimney flue (standard gas furnace) or a sidewall vent (condensing furnace).

Consumers may also incur connection costs if they do not already have natural gas service. These may include:

- Installing a gas service line from the street to the home.
- Installing a gas main line to the neighborhood, if needed.

IHS CERA has evaluated payback periods associated with a conversion from an electric resistance heating to a natural gas furnace for a variety of furnace sizes and for installation costs of $2,000 and $6,000 (see Table IV.5). Based on IHS CERA's projected average natural gas and electricity prices for 2012-35, the energy savings for a gas furnace using 60 MMBtu annual heating load in a northern market would be about $1,500 per year. For installations with a cost of $2,000, this would result in a 1.3 year payback period while those installations with a cost of $6,000 would have a 4 year payback period. However, payback periods increase rapidly as the size of the heating load decreases. Based on IHS CERA's projected natural gas and electricity prices for 2012-35, the energy savings for a gas furnace with a 20 MMBtu annual heating load in a southern market would be about $500 per year. For installations with a cost of $2,000, this would result in a 4-year payback period while those installations with a cost of $6,000 would have a 12-year payback period. This further confirms the advantage of natural gas over electricity in colder regions. In warmer markets, converting from electric resistance heating to an electric heat pump may be more attractive to some consumers, especially if the consumer does not already have natural gas service.

TABLE IV.5

Energy Savings from Converting Electric Resistance Heat to a Gas Furnace

	Natural Gas		Electricity				
Energy Price ($/MMBtu)	$11		$38				
Heating Load (MMBtu)	NG Fuel Input @ 80% Appliance Efficiency (MMBtu)	Cost	Power Input @ 98% Appliance Efficiency (MMBtu)	Cost	Annual Savings	Years to Payback for Installation Costs of: $2,000	$6,000
10	12.5	$136	10.2	$388	$253	7.9	23.7
20	25.0	$272	20.4	$777	$505	4.0	11.9
30	37.5	$407	30.6	$1,165	$758	2.6	7.9
40	50.0	$543	40.8	$1,554	$1,011	2.0	5.9
50	62.5	$679	51.0	$1,942	$1,264	1.6	4.7
60	75.0	$815	61.2	$2,331	$1,516	1.3	4.0
70	87.5	$950	71.4	$2,719	$1,769	1.1	3.4
80	100.0	$1,086	81.6	$3,108	$2,022	1.0	3.0

Source: IHS CERA

Overcoming obstacles to conversion to natural gas

There are several reasons why oil or electric heating customers are reluctant to convert to natural gas. These include lack of awareness of the potential operating savings from a conversion to gas. Many consumers do not understand that yesterday's high natural gas prices are expected to be a thing of the past. Gas LDCs need to educate prospective gas customers and suppliers of gas furnaces on the benefits of converting to gas.

The high capital, installation and connection costs can deter a consumer from converting, especially if their furnace does not need immediate replacement. Many potential customers do not have the financial wherewithal to finance the conversion. To overcome this obstacle, gas LDCs may need to establish above-the-line efficiency conversion programs or below-the-line or affiliate conversion financing programs.[63] These programs would finance the conversion costs over a fairly long period, allowing the customer to pay for the conversion costs from operating savings so as not to reduce their discretionary income. With many furnaces lasting 20 years and service lines and mains lasting 30 to 40 years, financing over 10 or more years may be appropriate. However, the longer the financing term, the greater the risk to the lender, a risk for which the gas LDC will have to be compensated. Financing over short periods, such as three years, might result in a reduction to the converting customer's discretionary income, not something many consumers will find attractive. Such financing programs will require educating not only prospective converting customers and suppliers of gas furnaces, but most importantly PUCs and other policy makers. Gas LDCs could lease equipment to customers shifting the first cost burden from the prospective customer to the gas LDC. The first cost burden of connection costs could be handled in a number of ways including using a surcharge to cover connection costs over a fairly long period rather than requiring a large up front lump sum contribution in aid of construction (CIAC).[64] Gas LDCs should support lower taxes on contributions in aid of construction to lower connection costs. As discussed below, gas LDCs could use anchor shippers to lower per unit cost of new mains.

Conversion potential

[63] Above-the-line capital costs and expenses are included in cost of service and used to design regulated rates. Below-the-line capital costs and expenses are not. The gas LDC's shareholders are at risk for below-the-line expenses which, depending on prospective revenues, may deter a gas LDC from pursuing conversion programs.

[64] On certain capital projects, the PUC can require the rate base to reimburse for all or a portion of project expenditures. The majority of such arrangements are associated with pipeline construction, some power plants, or production well tie-ins depending on the state. CIAC is netted against project cost as it is received.

Over the past decade the number of residential gas customers has increased by 5.7 million, of which about 4.8 million (85%) live in MSAs. If gas LDCs could convert over the next decade another 4.8 million oil and electricity customers living in MSAs to gas service, then based on 2011 natural gas use per residential gas customer of 71 Mcf per year, residential gas demand could grow by about 0.9 Bcf per day in ten years. For perspective, 2011 residential natural gas demand was 12.9 Bcf per day. This estimate focuses on potential customers that live in MSAs since that is where existing gas infrastructure is more likely, minimizing the cost of extending service to those conversion customers.

Natural gas versus electricity for multi-family space and water heating

In multi-family units, with rare exception, electricity has outcompeted gas as the heating fuel choice for new units since the mid-1970s (see Figure IV.9). By 2012 natural gas held only a 23% heating fuel market share for all new multifamily units, up slightly from 21% in 2000. Gas' share of the multi-family residential market has averaged about 20% less than its share of the single family residential market. More likely than not, developers of multi-family units will install electric space and water heating. Since electric space and water heating usually have a lower capital cost than natural gas space and water heating, developers often choose to install electric space and water heating even though the operating costs of natural gas will likely be lower than electricity. This is because the buyers or renters will pay future operating costs, not the developer. If prospective buyers or renters want natural gas, then developers will install natural gas.

To increase natural gas' share of new multi-family units, gas LDCs have several options. They need to educate the public and developers on the benefits of using natural gas. They should participate in developing building codes emphasizing not only the full fuel-cycle benefits of using natural gas, but also the full emissions-cycle benefits. Gas LDCs may want to establish an efficiency program under which the gas LDC provides a contribution in aid of construction to the developer. The gas LDC would then recover its investment through a surcharge to gas customers living in that building.

Other benefits from natural gas service

The above economic analysis, as well as most economic analyses, do not include as a benefit to using natural gas, rather than electricity or oil, the value of lower emissions from sulfur dioxide, nitrogen oxide, carbon dioxide, particulates, or ash. A potential benefit from extending natural gas service to new markets is that it can promote economic development by lowering energy costs for commercial or industrial end users that otherwise might have to use fuel oil, propane or even trucked in compressed natural gas or liquefied natural gas.

Other potential residential natural gas uses

As discussed above, residential natural gas demand is expected to remain relatively flat as continuing gains in energy efficiency offset growth in residential gas customers unless natural gas increases its share of residential energy requirements at the expense of oil or electricity. This section discusses other potential residential natural gas uses that could increase future residential natural gas demand.

Refueling units for natural gas vehicles

The main challenges to increasing natural gas in the light duty vehicle (LDV) market are less on the vehicle technology side, and more on the infrastructure side (such as the creating a network of CNG refueling sites) and in creating consumer acceptance of natural gas as a fuel that, in turn, translates into demand for natural gas-powered vehicles.

For 2011, the average residential natural gas customer consumed 71 Mcf.[65] The addition of a home refueling unit for a light duty natural gas vehicle (NGV) could increase annual demand for that customer by about 43 Mcf. This estimate is based on annual miles driven of 12,000, with fuel economy of 36 miles per gallon, and all refueling done at home.[66] Until the size of the NGV market increases significantly, there is likely to be little consumer demand for home refueling units. Until that occurs, gas LDCs can work with regulators and local governments to update regulations and building codes to accommodate home refueling units.

Chapter X examines consumer, industry, and policy challenges to light duty NGV adoption, but also opportunities to overcome these barriers.

Home back-up generator systems

A series of recent storms in the Northeast has resulted in a boom for home generators, which could be considered a form of distributed generation. Super Storm Sandy resulted in weeks-long outages on Long Island and coastal regions of New Jersey, and also produced the third major power outage in New England in two years. This event reinforced an awareness that power outages could be long, frequent and difficult to endure. Natural gas-fired home generators provide a backup system to power from the grid that can meet homeowners' and businesses' needs for power during grid failures. However, since backup generators only run when there is a power outage, incremental gas demand from such a customer would be very low. The cost of installing natural gas backup generators—$5,000 to $10,000—acts as a barrier to the widespread deployment of the units. Significant cost-reducing technologies are needed to improve prospects for gas-fired back-up generation moving beyond a niche market for residential natural gas. The resultant natural gas demand should be low. An average residential electric customer uses 31 kilowatt hours (kWh) a day or the equivalent of 0.105 Mcf per day (not including conversion losses necessary to generate the electricity). Assuming a heat rate of 20,700 Btu per kWh for a 20 kW unit operating at a 50% load factor, daily gas requirements could be 0.641 Mcf.[67] The use of a back-up generator should not reduce power generation gas demand.

Other potentially transformative residential natural gas appliances

Other potential residential natural gas applications are microCHP and fuel cells. Both of these technologies can be used to provide space and water heating as well as electricity. An average residential customer uses 11,280 kWh per year of electricity or the equivalent of 38.5 Mcf per year of gas before conversion losses.

There are two primary barriers to entry for CHP in the residential and commercial markets - the high initial investment cost and an uncertain return on investment. Chapter IX probes the other challenges as well as benefits of CHP. For instance, both microCHP and fuel cells should reduce a customer's full fuel-cycle energy consumption.

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[65] US Energy Information Administration.

[66] The Corporate Average Fuel Economy standard for light duty vehicles for 2016 is 36 miles per gallon.

[67] To assure reliability back-up units must generally be run at least 20 minutes per week or almost two full days per year.

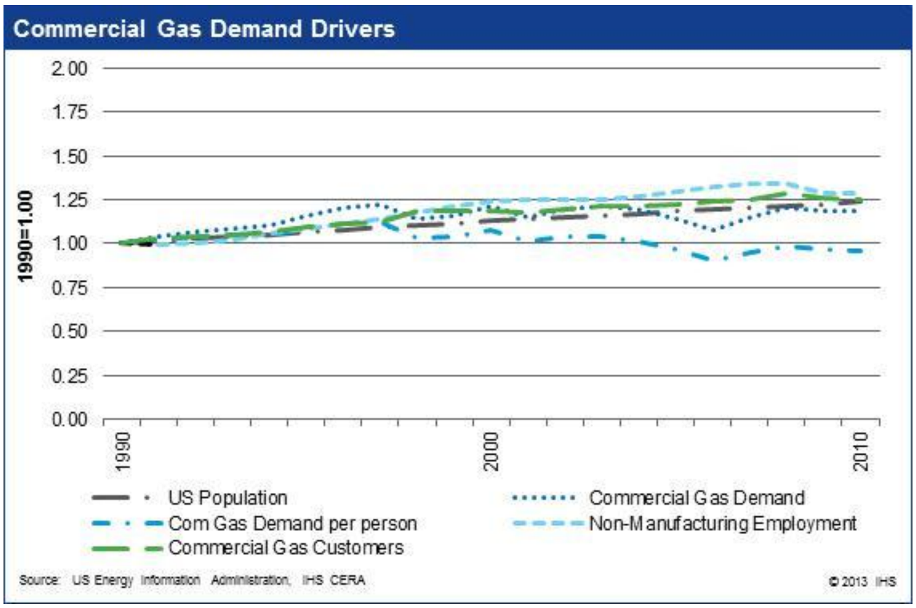
Drivers of commercial natural gas demand

The primary drivers of commercial natural gas demand are:

- Number of commercial gas customers
- Rate of commercial energy efficiency gains measured by changes in commercial natural gas consumption per commercial customer

As discussed in more detail below, the result of these drivers is that commercial natural gas demand has been and is expected to grow very slowly (see Figure IV.16).

FIGURE IV.16



More than 5.3 million commercial customers are connected to the natural gas grid across the United States. Commercial sector gas consumption comes from buildings associated with non-manufacturing activities, such as food sales and services (restaurants, fast-food establishments, bakeries, meatpacking plants etc.), education (day care facilities, schools, universities), assembly, health care, lodging, retail, dry cleaning, offices, libraries, and warehouses--a very diverse group making generalizations about the commercial natural gas market difficult. Similar to residential users, commercial customers use natural gas primarily for space heating (63%), water heating (17%), and cooking (7%, see Figure IV.4).

Among the major factors affecting natural gas demand in the commercial sector are weather, economic growth, use of floor space and equipment, and, particularly when choosing new equipment, natural gas prices relative to electric or oil prices. A shift in population and consequently commercial activity toward more temperate regions as well as increasing building and appliance energy efficiency has held commercial sector natural gas use fairly constant for 20 years. From 1990 to 2011 the number of commercial gas customers increased by 26%. [68] With natural gas demand per commercial customer declining at about 0.6% per year since 1990, weather normalized commercial natural gas demand increased by only 14% over this period.

Outlook for commercial natural gas demand

As for the future, most forecasters, including IHS CERA, expect little, if any, growth in commercial natural gas demand. If microCHP units or fuel cells become viable for commercial use, then commercial natural gas demand could be higher. Realizing these opportunities will be quite challenging and may require a rethinking of policies and programs by policy makers, PUCs and gas LDCs.

Opportunities to increase natural gas' share of commercial energy use

Natural gas competes with electricity, and to a much lesser extent with distillate fuel oil, as a space heating, cooking and water heating fuel choice in the commercial sector. The latter is predominantly used in buildings located in areas where gas distribution infrastructure is constrained or not available. Distillate's share of the commercial sector energy market has been significantly eroded over the last few decades, as environmental, cost and infrastructure benefits have made electricity and gas much more appealing to commercial customers. The remaining commercial distillate consumption for space and water heating in 2012, as estimated by EIA, was equivalent to about 0.4 Bcf per day.

Electricity used for space and water heating, space cooling and cooking in the commercial sector amounted to an estimated 1.5 Bcf per day of gas-equivalent in 2010 (see Table IV.1). As in the residential sector, with a wide disparity between natural gas and electric prices expected to persist over the long term, natural gas is well positioned to gain market share from electricity in the commercial sector (see the boxes "Restaurants: an opportunity for expanded gas consumption" and "Natural gas-fueled commercial space cooling").

[68] US Energy Information Administration.

Restaurants: an opportunity for expanded gas consumption

Restaurants are a vital cog in the US economy with over 980,000 locations nationwide, 13 million workers and over $660 billion in projected 2013 sales.[69]Natural gas and electricity costs represent 3% to 8% of total restaurant costs, according to the National Restaurant Association. As economic recovery gains momentum in the next few years, restaurant operators will be looking to invest in energy-saving kitchen appliances, refrigeration, ventilation and heating. Efficient and modern natural gas appliances are well positioned to be the primary choice for users replacing worn out gas- or electric-fired equipment. An overwhelming majority of restaurants are located within the core service regions of LDCs, metropolitan areas, which would allow utilities to expand deliveries to existing customers or to hook up new customers.

The expected cost advantage of natural gas compared to electricity for restaurant use is illustrated in Table IV.6, which compares the life-cycle costs of two identical modern and efficient gas and electric kettle fryers.[70] These appliances are used for deep-frying a variety of foods, from chicken to doughnuts to vegetables. Both fryers are 18.5” with nominal frying oil capacity of 75 pounds. The gas fryer has dual burners, a gas heat exchanger, and an 85,000 Btu-per-hour input rate. The electric fryer has tubular sheath heating elements and a 20 kW rated input rate. While the electric kettle fryer exhibits lower energy needs for preheating, idling and overall consumption for identical output and performance, the gas fryer has a clear cost advantage, as the average retail electricity price to commercial customers is projected to continue to be between 3 and 4 times higher than the retail gas price (see Figure IV.12). Similar analyses for griddles, broilers, combination ovens and cooktops show that natural gas has an advantage over electricity on a pure energy cost basis.[71]

[69] National Restaurant Association

[70] This analysis assumes a similar retail price and maintenance expenses.

[71] Other factors for consideration may include ease of operation, heat generation in the workspace, ventilation and maintenance and so forth.

TABLE IV.6

Natural Gas vs. Electric Fry Kettle Comparison	Giles GGF-720 Gas Fry Kettle	Giles GEF-720 Electric Fry Kettle
Performance:		
Preheat Energy: (Btu) or (kWh)	13,038	3
Idle Energy Rate: (Btu/h) or (kW)	5,645	1
Heavy-Load Energy Efficiency: (%)	61	85
Production Capacity: (lbs/h)	80	96
Usage:		
Operating Hours per Day: (h/day)	12	12
Operating Days per Year: (d/year)	365	365
Number of Preheats per Day: (#/day)	1	1
Pounds of Food Cooked: (lbs/day)	150	150
Utility Cost and Lifespan:		
Gas Cost per Therm: ($/therm) or ($/kWh)	1	0
Lifespan of Fryer: (years)	12	12
Discount Rate: (%/year)	-	-
Other:		
Maintenance Costs per Year:	200	200
Initial Cost of Fryer:	4,000	4,000
Results:		
Annual Energy Consumption: (Therms) or (kWh)	765	15,396
Average Energy Consumption Rate: (Btu/h)	753	1,848
Lifetime Energy Cost:	9,036	22,176
Lifetime Maintenance Cost:	2,400	2,400
Initial Cost of Fryer:	4,000	4,000
Total Lifetime Cost:	**15,436**	**28,576**

*Data from December 2011

Calculator and fryers data source: www.fishnick.com; assumptions modified by IHS CERA

Refueling stations for natural gas vehicles

The medium duty NGV fleet is expected to grow over the long-term, roughly at the pace of economic growth. Parts of this market are a natural fit for natural gas fueling since much travel takes place on defined, short-range and consistent routes. These vehicles are used for a broad set of applications, including construction, agriculture, retail, school buses, waste management, utilities, and wholesaling.

Although medium duty NGVs do not need a large natural gas infrastructure, they clearly face some of the same infrastructure hurdles as other vehicle segments looking to convert to natural gas. An expansion of public-access CNG infrastructure is, therefore, a key to creating more natural gas demand from commercial vehicles.

Construction of more CNG refueling stations could increase commercial natural gas demand. Assuming each NGV fill-up is the equivalent of 20 gallons, each refill would be 2.1 Mcf per NGV. Until the NGV market increases significantly, there is likely to be little demand for CNG refueling stations. Until that occurs, gas LDCs should work with regulators and local governments to update regulations and building codes to accommodate CNG refueling stations.

Typical payback times for the higher initial costs of medium duty NGVs are three to five years, depending on vehicle miles travelled. The more a vehicle is driven, the more quickly fuel savings accumulate. Chapter X examines natural gas in the transportation sector in greater detail.

Other potentially transformative commercial natural gas appliances

Other potential commercial natural gas applications are microCHP and fuel cells. Both of these technologies can be used to provide space and water heating as well as electricity. Given the diversity in type and size of commercial customers, it is hard to generalize about the size of natural gas demand opportunities. However, some large commercial customers are probably better candidates for these technologies than residential customers as larger units should have lower costs per unit of output. Viable commercial entities may be hospitals, universities, military installations, prisons, and nursing homes.

Furthermore, microCHP and fuel cells would reduce the vulnerability to grid outages improving electric reliability. Both microCHP and fuel cells should reduce a customer's fuel-cycle energy consumption including any reduction in power generation natural gas demand. How much the reduction in power generation gas demand will be is a function of the generation mix of the consumer's electric supplier. The potential for natural gas demand from microCHP and fuel cells is discussed in greater depth in Chapter IX.

Natural gas-fueled commercial space cooling

Although natural gas is primarily utilized in the commercial sector for space and water heating and cooking (together accounting for nearly 72% of 2012 commercial natural gas end-use as estimated by the EIA), gas-fired cooling technology has been available in the marketplace for many years and provides an alternative to electric HVAC equipment, which is by far the predominant choice of commercial building operators.

Natural gas engine and absorption chillers are the two main types of cooling appliances. The former utilizes a gas-fired engine, similarly to electric coolers, to perform a vapor compression cycle. An added benefit of these chillers is that waste energy and exhaust heat could be subsequently recovered for space, water or process heating, which improves the economic performance. Absorption chillers are complex machines, which essentially rely on thermochemical compression to cool water or another refrigerant, using thermal energy as an input. Natural gas could be the source of the required thermal energy (direct-fired chillers) or waste heat, hot water or excess steam from a natural gas-fuelled CHP system may be used (indirect-fired chillers). Absorption chillers could be converted to provide space heating, but cannot offer both heating and cooling services simultaneously.

The cost-benefit analysis on both types of gas-fired chillers largely depends on the relative cost of gas versus electricity that commercial customers pay. Electric chillers tend to be more efficient than even the most advanced gas-fired ones, so the fuel price differential must be substantial to justify installation.

Using anchor customers to support expansions

As discussed further in Chapter VI, the economics of an expanded natural gas distribution system can be improved if the gas LDC can sign up an anchor customer, a large commercial or industrial customer such as a new plant, a housing subdivision, a shopping center, a hospital, or even a power plant. This would allow for construction of a line with more capacity with a lower cost per unit of throughput. This should reduce the required contributions from new customers or, alternatively, reduce any surcharge on new customers. Anchor shippers could come from the commercial, industrial, or power sectors. Chapters VII and VIII discuss the expected growth in natural gas consumption in the industrial and power sectors, respectively, and how gas LDCs might benefit from this growth.

Implications for gas LDCs

With concerns about natural gas availability and price subsiding, there is a clear opportunity for gas LDCs to increase deliveries to existing customers and expand their systems to serve new customers. However, considerable marketing efforts and changes in regulatory policies and LDC practices may be required in many gas markets.

The primary drivers of residential and commercial natural gas demand are population growth and the rate of improvement in energy efficiency. Growth in population has and is expected to continue to occur mostly in the South and West, areas which have lower heating requirements, but higher cooling requirements. Since 1990, these drivers have essentially offset each other resulting in little or no growth in residential and commercial natural gas demand.

To change the historical growth paradigm, natural gas has to increase its share of residential or commercial fuel through conversions from fuel oil or electricity for single family and multi-family households or commercial customers, improve the competitiveness of natural gas furnaces versus electric heat pumps, install significant numbers of home refueling units for natural gas vehicles (NGVs), construct significant numbers of CNG refueling stations, or achieve transformational breakthroughs in microCHP units or fuel cells.

One way to expand natural gas use in core gas LDC markets is to replace existing electric and oil appliances with natural gas appliances. In most regions, a natural gas furnace or water heater can have significant cost and efficiency advantages over a comparable oil or electric appliance. However, where additional pipeline capacity is required, the high up front LDC costs and, in some cases, difficulty in getting regulatory approvals for the expansion may slow the rate of conversions. Furthermore, high installation costs can act as a barrier to conversions. As discussed in Chapter VI, there are ways to address the up front cost issue while avoiding higher rates for existing customers and protecting competing fuel suppliers.

Realizing some of these opportunities will be quite challenging and may require a rethinking of policies and programs by policymakers, PUCs and gas LDCs.

Gas LDCs can increase their markets by:

- Working with customers and PUCs to increase access to natural gas, help existing customers to increase their use of natural gas as desired, and extend LDC systems to serve new customers.

- Working with state governments and PUCs to change any legislation or regulatory policies that discourage the servicing of new gas load, especially if that load would improve overall energy efficiency, reduce emissions, and is economical.

- Working with PUCs, community leaders, financial institutions, and appliance manufacturers to develop mechanisms to reduce the effect of high up front costs to both the gas LDC and the consumer, costs which can deter customers from converting to natural gas, while avoiding adverse effects on existing gas LDC customers.

- Working with PUCs and developers of multi-family buildings to reduce the initial first cost of installing natural gas space and water heating systems, while educating potential buyers or renters on the operating cost advantage of natural gas versus electric space and water heating.

- Overcoming approaches in many efficiency rulemakings which discourage inter-fuel comparisons and result in promoting inefficient technologies, backed originally by site energy efficiency analysis as discussed in Chapter V. PUCs will need to assure that there is a level competitive playing field for all energies, but especially between gas and electricity.

Chapter V: The Role of Natural Gas in Promoting US Residential and Commercial Energy Efficiency

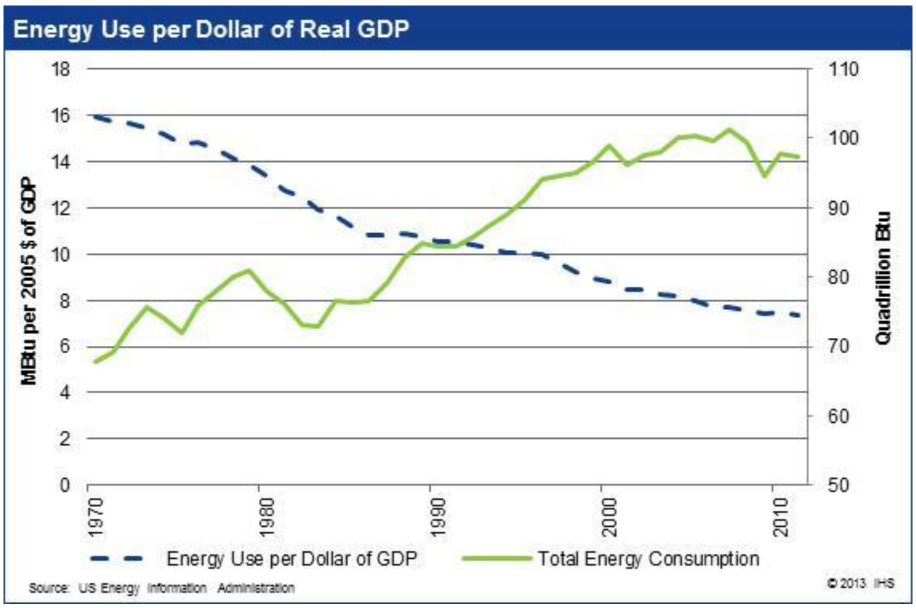
In Brief

- Since the 1970s, increasing the efficiency of energy use has been a priority of national energy policy. Major gains have been achieved by appliance energy standards, stricter building codes, and site energy efficiency programs. These programs all focus on improving energy efficiency at the point of consumption and were developed in era when natural gas was considered a scarce and expensive resource.
- State governments, PUCs and gas LDCs should consider how abundant, reasonable cost natural gas supplies can now be used to help improve total energy efficiency and reduce overall emissions. Policies that support greater direct use of natural gas should be underpinned by full fuel-cycle energy efficiency analyses, full fuel-cycle emissions analyses, and life cycle cost analyses. Use of these tools can identify regions and applications where greater direct natural gas use would contribute societal benefits of improved energy efficiency, reduced emissions, and economic efficiency. PUC and gas LDC policies on adding customers and extending service to new markets may need updating to facilitate a shift from site energy efficiency to a full fuel-cycle energy efficiency paradigm.
- From a full fuel-cycle perspective, natural gas is more energy efficient for some applications than electricity which uses large amounts of energy to produce and deliver electricity. In many regions, converting from electricity to natural gas for space heat, water heat, and cooking can increase total energy efficiency by avoiding these conversion losses. Because the already large disparity between retail natural gas prices and retail electricity prices is expected to widen over time, increasing natural gas' share of these markets can increase cost efficiency as well.
- Natural gas is also more energy efficient and cost efficient than fuel oil for some space and water heating applications, especially in the Northeast.
- Many states have implemented revenue decoupling adjustments to assure gas LDCs that they can recover their fixed costs even if energy efficiency efforts reduce natural gas throughput on their systems. These adjustments are intended to make a gas LDC indifferent to changes in the amount of natural gas delivered on its system. Some PUCs and gas LDCs may wish to update the terms of decoupling programs to encourage the adoption of full fuel-cycle energy efficiency goals which could result in increased direct use of natural gas, thereby reducing total energy consumption.

Conserving energy and increasing energy efficiency (i.e., reducing energy input relative to energy output) has been a priority of national energy policy for decades. In 1975, the Energy Policy and Conservation Act established Corporate Average Fuel Economy (CAFÉ) standards for vehicles. The National Energy Conservation Policy Act of 1978 directed the Federal Government to establish residential energy efficiency programs and appliance efficiency standards. It also established requirements for energy management by federal agencies. The Energy Policy Act of 1992 mandated energy efficiency standards. The Energy Policy Act of 2005 and the Energy Independence and Security Act of 2007 both contained additional support for energy efficiency and conservation measures. Most recently, the Emergency Economic Stabilization Act of 2008 and the American Recovery and Reinvestment Act of 2009 provided tax credits and other financial incentives for energy efficiency investments. These efforts—together with the normal demand response to rising energy prices—have borne fruit. Energy use per dollar of GDP declined from 15.9 thousand Btu (MBtu) per dollar of GDP in 1970 to 7 MBtu per dollar in 2012—a decline of 56% (see Figure V.1).

Note that energy efficiency and energy conservation are not the same. Energy efficiency is a characteristic of energy use, measured as the ratio of usable energy provided (such as space heat) to the amount of energy input (such as natural gas or electricity). Energy conservation involves reductions in energy use—turning down thermostats or driving fewer miles. The reduction in energy use per dollar of GDP shown in Figure V.1 demonstrates that energy efficiency has improved. However, increasing energy efficiency did not reduce energy consumption—which grew from 67.8 quadrillion Btu (quads) in 1970 to 97.3 quads in 2011—but it slowed the growth of energy consumption relative to the growth of GDP.

FIGURE V.1



Increasing the energy efficiency of appliances and stricter building codes that improve the thermal efficiency of buildings played a part in slowing the growth of residential and commercial natural gas consumption over the past 25 years. Since 1990, natural gas consumption in these two sectors has held fairly steady at approximately 21 Bcf per day, even though the number of customers has increased substantially. Gas use per customer has declined in both sectors (see Figures V.2 and V.3). Residential gas use per customer is down 25% from its peak in 1996. Commercial gas use per customer peaked in 1997 and has since declined by 14%. Year-to-year variations in gas use per customer are mostly a function of variations in weather from year to year.

FIGURE V.2

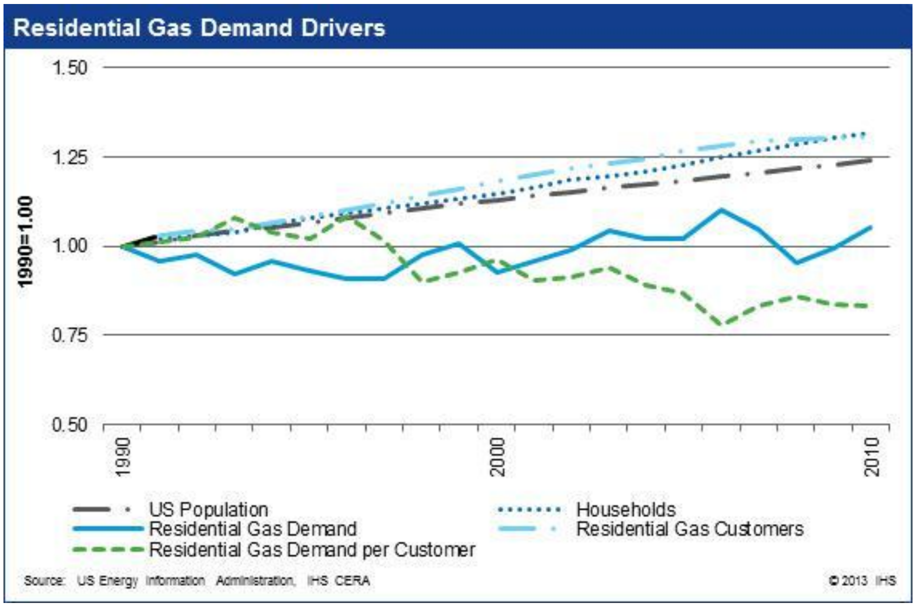
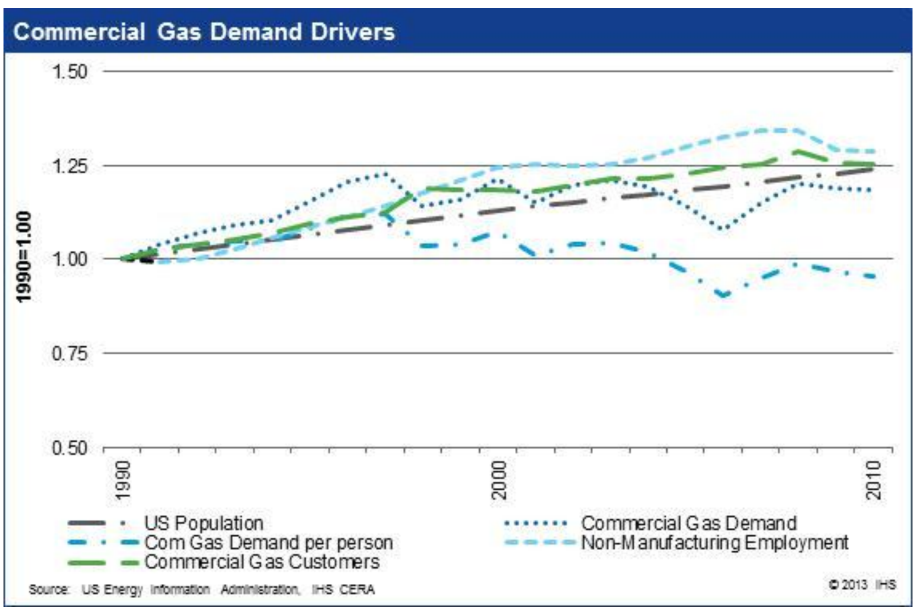


FIGURE V.3



Drivers of energy efficiency gains in the residential and commercial sectors

Reasons for declining gas use per customer include:

- Stricter building codes that improve the energy efficiency of buildings
- Growing energy efficiency of natural gas appliances
- Gas LDC energy efficiency programs
- Tax credits for energy efficiency investments

Building code energy efficiency programs

State and local building codes govern the construction of new and renovated residential and commercial buildings. Most of these local codes are based on model codes and standards developed by the International Code Council (ICC) and by the American Society of Heating, Refrigerating and Air-Conditioning Engineers (ASHRAE). The US DOE's Building Energy Codes Program works closely with both groups to develop model standards for the energy component of building codes. The energy codes aim to increase the energy efficiency of buildings and equipment. Once adopted, new and renovated buildings must comply with the codes. Enforcement of building codes is generally the purview of state and local regulators. The ICC and ASHRAE energy codes are updated every three years.

In addition to these mandatory building codes, the expansion of two voluntary market programs for building labeling and certification illustrates the momentum behind increasing commercial building energy efficiency. The LEED (Leadership in Energy and Environmental Design) initiative administered by the US Green Buildings Council (USGBC) is an optional third-party verification program that certifies existing buildings and new projects at any point in their life cycle. Certification is based on a number of green criteria including Sustainable Sites, Water Efficiency, Energy and Atmosphere, Materials and Resources, and Indoor Environmental Quality.[72] Projects can be registered with the USGBC at any point in the project life cycle. LEED registrations have grown from about 1,000 projects in 2002 to nearly 15,000 LEED certified and pre-certified buildings by 2013. Another 30,000 are currently in various stages of assessment. More than half of the LEED-certified buildings are in nine states (California, Florida, Illinois, Massachusetts, New York, Pennsylvania, Texas, Virginia and Washington) and the District of Columbia.

Another voluntary program is EPA's EnergyStar labeling for commercial buildings. The EPA uses a complex EnergyStar energy performance scale (1-100) to measure, track or benchmark a building's energy performance relative to a peer group of buildings with similar characteristics. The energy performance rating is derived by selecting a nationally representative dataset (typically the most recent Commercial Building Energy Consumption Survey (CBECS) from EIA), analyzing the building's energy performance in terms of source energy consumption (fuel mix), performing regression analysis on the reference dataset to identify key drivers of consumption (weather, hours of operation, number of workers, number of computers, etc.) and finally determining the distribution of energy performance across the

[72] http://new.usgbc.org/sites/default/files/Docs3330.pdf.

population of buildings against which the building in question is to be measured.[73]

To qualify for EnergyStar certification, a building must have a performance rating in the top 25% of its peer group and must be independently verified by a licensed professional engineer or a registered architect. EnergyStar certified buildings use an average of 35% less energy and are responsible for 35% less CO_2 emissions than the average building, according to the EPA.[74] From 2007 to 2009 the number of EnergyStar buildings more than doubled, from 4,000 to almost 9,000 and as of February 2013 there were nearly 21,000 certified commercial establishments. Similar to the trends in the LEED initiative, most EnergyStar certified buildings are in major metropolitan areas, led by Los Angeles, Washington, DC, and Chicago.[75]

EPA also has an EnergyStar program for homes. EnergyStar certified new homes are designed and built to standards well above most other homes on the market today, delivering energy efficiency savings of up to 30% when compared to typical new homes.[76]

Appliance energy efficiency programs

In addition to the increasing thermal integrity of buildings, the increasing efficiency of natural gas appliances has contributed to the lack of growth in residential and commercial natural gas demand over the past decades. A number of laws dating back to the Energy Policy and Conservation Act of 1975 have involved the federal government in setting energy efficiency standards for appliances. According to studies by the American Gas Association (AGA), efficiency gains in natural gas furnaces and gas water heaters account for over half of the decline in per-household natural gas consumption since 1980.[77] A standard residential gas furnace in 1980 had 65% annual fuel utilization efficiency (AFUE) (see the box "Measuring appliance energy efficiency"), while today the least efficient gas systems are 80% efficient, and almost one-third of furnaces sold today have 90% efficiency or higher (see Table V.1).[78] Similarly, the efficiency of a gas water heater increased from an average of 50% in the 1980s to over 67% today for high-efficiency gas storage water heaters. (These efficiencies are calculated on a site-efficiency basis, as discussed further below. Full fuel-cycle efficiencies would be about eight percentage points lower to account for the energy used to produce and deliver the natural gas to the point of use.)

[73] www.energystar.gov/ia/business/evaluate_performance/General_Overview_tech_methodology.pdf.

[74] www.energystar.gov/buildings.

[75] http://www.energystar.gov/ia/business/downloads/2011_Top_cities_chart.pdf?f896-0857.

[76] http://www.energystar.gov/index.cfm?c=new_homes.hm_index.

[77] http://www.eia.gov/pub/oil_gas/natural_gas/feature_articles/2010/ngtrendsresidcon/ngtrendsresidcon.pdf.

[78] Note that these efficiencies are site efficiencies. Full fuel-cycle efficiencies are about 8% lower, as discussed in the next section.

TABLE V.1

Site-Specific Energy Efficiency of New Natural Gas Appliances		
Shipment Weighted Averages		
	1972	2006
Rated by Average Fuel Use (AFUE)		
Gas Furnace	65%	84%
Condensing Gas Furnace		96%
Gas Water Heater	50%	67%
Tankless Gas Water Heater		80%

Source: Lawrence Berkeley National Laboratory, EETD/EAD [July 2007]

Measuring appliance energy efficiency

Energy efficiency is measured as a ratio of usable energy output (heat or cooling) provided per unit of energy input. Measures differ by fuel and appliance but all are basically a coefficient of performance (COP), a term commonly used in thermodynamics that relates energy output to energy input. A COP of 75%, for example, would indicate that the useful energy (in Btu) produced by the appliance is equal to 75% of the energy input (in Btu) to the appliance. In other words, the appliance is 75% energy efficient.

For natural gas space heating, energy efficiency is measured as the AFUE, which is conceptually the same thing as a COP. AFUE reflects the amount of usable heat produced by a furnace compared with the energy produced by the fuel being burned. For example, an 80% AFUE gas furnace converts 80% of the natural gas energy content to heat the home, while 20% of the heat is vented outdoors.

For electrical appliances using compressors (refrigerators, heat pumps, air conditioners) an Energy Efficiency Ratio (EER) is calculated, expressed in terms of Btu of heat or cooling output per kWh of electricity input.[79]

In the case of air conditioners and heat pumps the measurement is seasonal and reflects the performance of the system over a wide range of temperatures. For air conditioners, a Seasonal Energy Efficiency Ratio (SEER) is determined across a wide range of indoor and outdoor temperatures. The standard air conditioner SEER is determined for indoor temperatures of 80° F with 50% relative humidity and outdoor temperatures of 95° F. For heat pumps, efficiency is measured in a Heating Season Performance Factor (HSPF) which is basically the EER of the heating season.

Policy makers should consider standardizing how energy efficiency is measured to facilitate full fuel-cycle analysis.

[79] 1 kWh contains 3,412 Btu.

Gas LDC energy efficiency programs

US gas LDCs have long encouraged energy efficiency programs and have demonstrated their commitment through investment. During 2011, nearly $1 billion was invested in 128 programs operating in 39 states and commitments climbed to a budget of $1.4 billion in the 2012 program year.[80] These energy solutions include efficient appliance rebates, incentives for efficient new homes and buildings, subsidies for home and building weatherization and retrofits, energy audits, contractor and building operator training, and certifications (see the box “Innovative programs / flexible regulation”). These are examples of successful and innovative natural gas efficiency programs. More information can be found at the gas LDCs’ web sites or from the American Council for an Energy Efficient-Economy.[81] According to the American Gas Association, these programs have yielded meaningful reductions in energy usage, helping residential participants save on average 13 percent of household gas usage and $107 in annual energy cost savings for participating residential customers (2011 program year).

[80] American Gas Association, *Natural Gas Efficiency Programs Report – 2011 Program Year, January 2013.*

[81] Seth Nowak, Martin Kushler, Patti Witte and Dan York, *Leaders of the Pack: ACEEE’s Third National Review of Exemplary Energy Efficiency Programs,* American Council for an Energy-Efficient Economy, Report Number U132, June 2013.

Innovative programs / flexible regulation

Public Service Electric & Gas Company. This program targets hospitals for energy efficiency improvements, whereby the gas LDC bears all the up front costs. As 24-hour-a-day/seven-day-a-week operators, hospitals present a great opportunity for impacting energy usage. PSE&G provides free energy audits and makes efficiency recommendations, and provides up front funding for the project. The hospital repays only a portion of the total cost (30% on average) at zero percent interest over a three-year period.

Nicor Gas Economic Redevelopment Program. This program targets existing commercial, industrial and large multi-family buildings in economically challenged areas and provides financial incentives that make efficiency projects more affordable. Eligible organizations typically offer community services such as health care, education, affordable housing and job creation or retention. The program also supports the refurbishment of contaminated industrial sites with energy efficient facilities.

CenterPoint Energy's Foodservice Program. This program began with a focus on educating residential customers on the benefits of cooking with natural gas, but later shifted to the commercial foodservice market, including restaurants, schools, and healthcare. The program offers rebates for broiler, convection ovens, fryer, pre-rinse spray valves and other equipment, and provides training at the company's Foodservice Learning Center. By targeting the foodservice sector, the gas LDC is able to target a sector that has rapidly increased its energy usage over the last few years.

Xcel Energy's Process Efficiency Program. To appeal to large industrial customers, Xcel broadened its program from prescriptive measures to a whole system approach, beginning with an analysis of total energy use and moving to creating a three-to-five year customer implementation plan. The program evaluates the entire system, from equipment used in the manufacturing process, to business practices and their influence on energy usage, to the building's HVAC and lighting systems.

Pacific Gas and Electric Company's Retrocommissioning Program (RCx). This program provides incentives and connects industrial customers with experts that will evaluate facilities'equipment and systems to make sure that they are running in peak condition to optimize energy savings. Incentives are paid to customers based on achieved annual energy savings at the rate of $1 per therm, capped at 50% of the total project cost. RCx is a systematic process for identifying less-than-optimal performance in the facility's equipment, lighting and control systems and making the necessary adjustments. While retrofitting involves replacing outdated equipment, RCx focuses on improving the efficiency of what's already in place.

National Grid's EnergyWise Program. This program was designed to provide residential customers in Massachusetts with measures and education to improve energy efficiency. It originally included both single and multi-family residences, but has since focused on the multi-family market and created a separate one-stop program for single-family residences. The program incorporates the goals of market transformation, resource acquisition, and consumer education. It provides incentives, on site energy audits and training to end users. The program pays 50% of the cost up to $1,500 for additional insulation, air sealing and other measures, and offers low-interest financing. Incentives are also available to replace inefficient lighting, refrigerators, and heating systems.

NiSource/Columbia Gas of Ohio's WarmChoice Program. This is one of the many gas LDC programs that serve low-income customers. WarmChoice targets households with high natural gas usage whose income falls at or below 150% of the federal poverty guidelines. Typically these customers have accumulated high past due bills. This sector thus provides a high potential for energy savings and a reduction in past due customer bills. The program often leverages funds from the federal low-income weatherization assistance program, and services are provided at no cost to eligible households—including energy audits, home weatherization, and repair or replacement of space and water heating systems.

Cost recovery for energy efficiency programs

A supportive regulatory framework is necessary for the continuance and growth of natural gas efficiency programs. Important to the success of these programs is ensuring that gas LDC incentives are aligned with energy efficiency goals. Effective regulatory approaches help gas LDCs recover lost revenues and preserve financial stability, so they are able to partner with their customers in reducing energy usage.

In traditional rate designs, a portion of fixed costs are recovered via a volumetric charge or a price per unit. With this type of rate structure, a gas LDC is at risk of under-recovering its fixed costs should customers reduce their consumption thereby lowering revenue from the volumetric charge. With growing interest in energy efficiency, state policy makers have increasingly approved cost tracking mechanisms and innovative (non-volumetric) rate designs that allow gas LDCs to recover energy efficiency program costs and lost sales revenue resulting from reductions in gas consumption.[82] They have also approved financial mechanisms that reward ratepayers and shareholders for successful investments in energy efficiency programs—quantifying the value of these demand-side programs and placing them on a more equal footing with alternative gas LDC investments.

The use of cost tracking mechanisms and non-volumetric rates has grown rapidly during the past few years, resulting in more than 75% of US residential natural gas customers being served via non-volumetric rate designs, as calculated from AGA data. Table V.2 describes the various mechanisms regulators have implemented to facilitate ratepayer-funded natural gas energy efficiency programs.

As of August 2013, 78 gas LDCs, serving 45 million residential customers in 36 states, had used at least one of these Efficiency Program Recovery Cost Mechanisms (see Figure V.4).

- Decoupling tariffs: 46 gas LDCs in 21 states serving 28 million customers
- Flat monthly fee or SFV rate design: 23 gas LDCs in 14 states with 10 million residential customers
- Rate stabilization tariffs: 18 gas LDCs in 10 states serving 7 million residential customers

In most cases, the revenue adjustment was negligible—approximately $1.40 per month for the average natural gas customer.[83]

[82] American Gas Association.

[83] Pamela Morgan, Graceful Systems LLC. *A Decade of Decoupling for US Energy Utilities: Rate Impacts, Designs, and Observations,* February 2013.

TABLE V.2

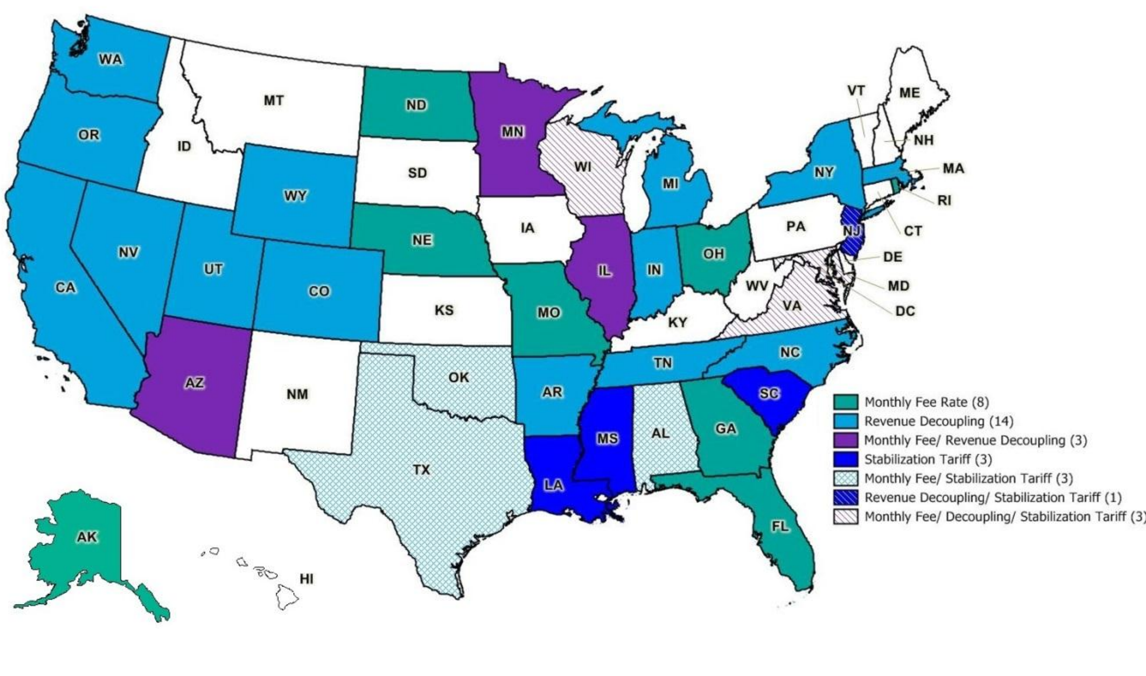
Types of Energy Efficiency Program Cost Recovery Mechanisms

A. DIRECT PROGRAM COST RECOVERY Gas LDCs pass through efficiency costs to customers in one of three ways: base rates, deferral accounts, or trackers.	
Base Rate	In a general rate case, efficiency program costs are treated as expenses and are embedded in the gas LDC's base rates (or the charge per unit).
Deferral Account	Program costs accrue and are tracked in a balancing account for amortization and recovery from customers over a period of time.
Trackers	Costs are recovered via a separate tariff rider or a surcharge on a customer's bills (also known as systems benefits charge), and the surcharge is adjusted periodically to correct for over- or under-recovery of costs.
B. LOST MARGIN RECOVERY Recovery of efficiency program costs and associated lost margins removes the gas LDC's disincentive to promote energy efficiency, thereby making program implementation revenue neutral. Margin recovery is achieved through non-volumetric rate designs (such as revenue decoupling, revenue stabilization and straight fixed variable rates) and through lost revenue adjustment mechanisms.	
Non-Volumetric Rate Structures	A rate design that allows gas LDCs to collect revenues from customers independent of therm usage. Here margin recovery is not applied on a per therm basis but rather approximates a per-customer basis of recovery. This type of rate structure includes revenue decoupling, straight fixed variable (SFV) rates, and rate stabilized mechanisms.
Revenue Decoupling	Decoupling breaks the link between gas LDC revenues (or profits) and gas throughput (or delivered volumes). The mechanism may be applied to total revenues or on a per-customer basis. Recovered revenues that diverge from the regulator-allowed recovery amount are trued up via periodic rate adjustments that address the over- or under-recovery. Revenue variances specific to efficiency may be tracked in a separate balancing or adjustment account and applied to the next rate adjustment. These mechanisms go by different names, such as conservation riders, conservation enabling tariffs, conservation incentive programs, conservation margin trackers, and the like.
Revenue Stabilization	This mechanism (also known as rate stabilization) combines lost margin recovery with the recovery of operating costs. Rates are adjusted periodically to adjust for variances from the regulator-authorized return on equity and for gas LDC cost variances since the last rate adjustment.
Straight Fixed Variable	With SFV rates, there are no revenue impacts resulting from efficiency programming, because most or all fixed costs are recovered via a non-volumetric charge. That is, the per-customer charge remains stable regardless of fluctuating consumption, thereby approximating a flat monthly fee.
Lost Revenue Adjustment Mechanism	This mechanism requires the gas LDC to identify unrecovered margins associated with efficiency programming, track them over a period of time, and recover them after the fact. In this case, revenues continue to be recovered on a therm usage basis; however, rates are adjusted for under or over-recovery of margins. This type of margin true is also referred to as a conservation adjustment mechanism.

C. GAS LDC PERFORMANCE BASED INCENTIVES	
To incentivize investor-owned gas LDCs to commit fully to efficiency program improvements and expenditures, regulators have gradually approved more mechanisms that financially reward gas LDCs and their customers for making energy efficiency investments. Efficiency performance-based incentives involve three mechanisms: shared savings, performance targets, and rate of return incentives.	
Performance Targets	As conditions for capturing earnings on efficiency investments, goals may be set for expenditure levels, energy savings, cost-effective savings, or installed units. Financial awards may be tiered to match performance levels—attaining a percentage, meeting the target, or exceeding it. Awards are often capped, and penalties sometimes apply if the gas LDC falls short of the minimum requirements.
Shared Savings	This mechanism rewards a gas LDC for either meeting a minimum threshold of spending on efficiency resources or for implementing programming cost-effectively by granting it a percentage of efficiency spending or of the resulting net system benefits. Commonly investors share the savings with ratepayers.
Rate of Return	Rate of return incentives allow earnings on natural gas efficiency expenditures, either equal to the gas LDC's authorized return on equity or at an enhanced level—a bonus return on equity for efficiency investments.

FIGURE V.4

Energy Efficiency Program Cost Recovery Mechanisms



Source: American Gas Association, National Resources Defense Council

Site energy efficiency versus full fuel-cycle energy efficiency

"Site energy efficiency" refers to efficiency measurements taken at the point of final energy consumption. For example, appliance energy efficiency labels report electricity or gas input to the appliance versus useful energy produced by the appliance. The use of site energy efficiency is limiting in that it does not take into account the energy necessary to produce and deliver energy to a site. A more relevant measure is the “full fuel-cycle” efficiency, or “primary energy” efficiency, which includes all the energy required to produce and deliver gas or electricity to the appliance versus useful energy produced by the appliance (see Figures V.5 and V.6). By comparing the areas labeled “site energy” with those labeled “full fuel-cycle energy” in Figure V.5 for residential consumption, one can see how incomplete the energy picture is when energy analysis is limited to just site energy consumption instead of full fuel-cycle. Figure V.6 shows a similar comparison for the commercial sector. A site analysis also gives an incomplete picture of emissions of sulfur dioxide, nitrogen oxide, carbon dioxide, mercury and particulates from the generation of power used by consumers.

FIGURE V.5

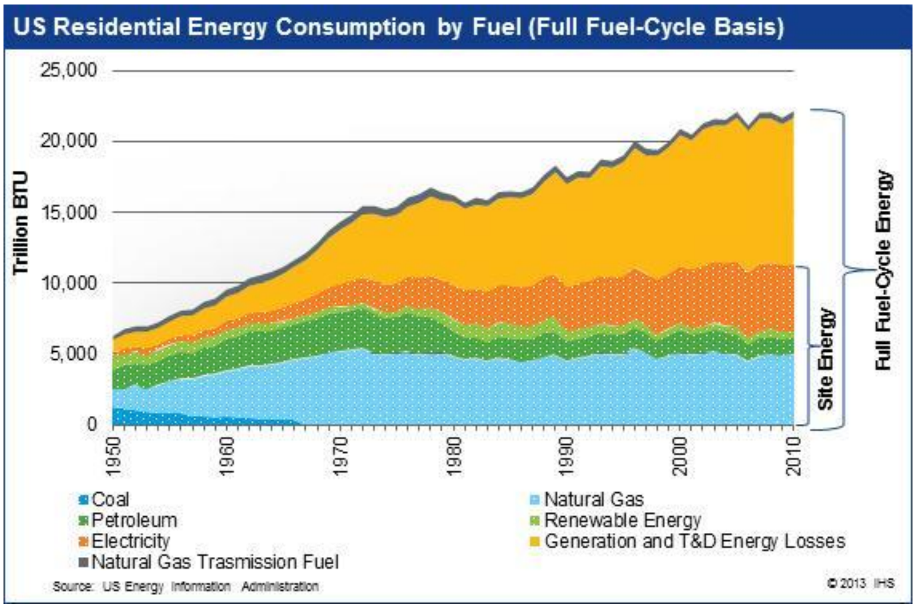
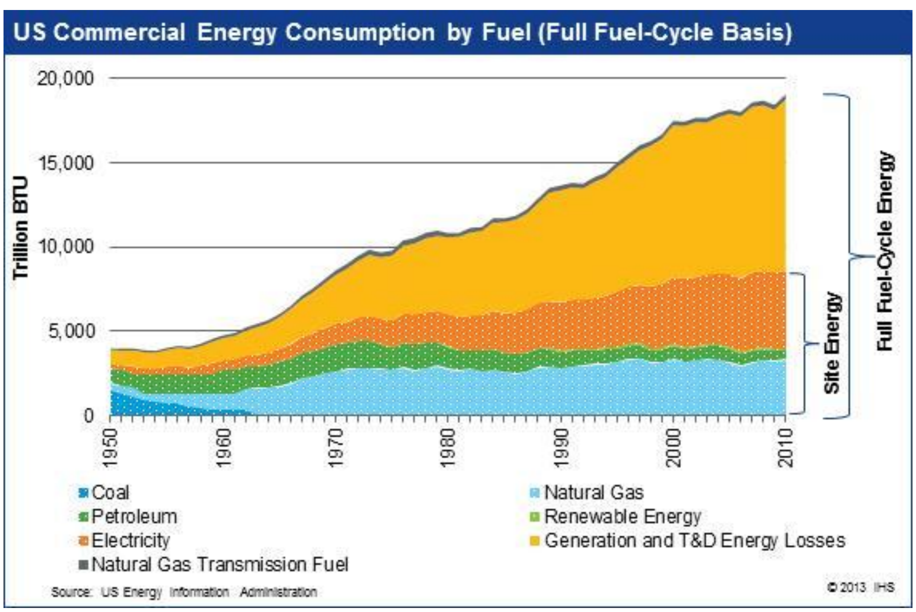
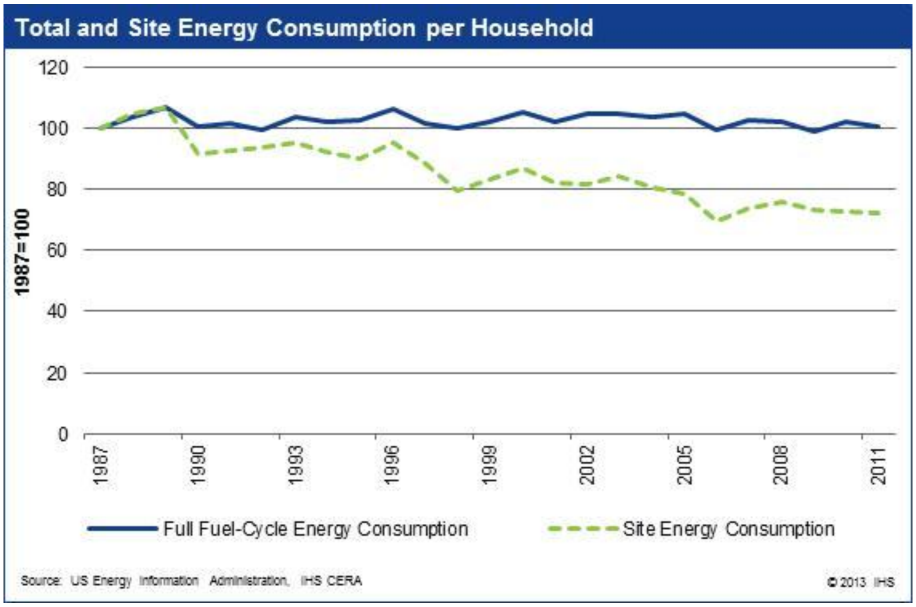


FIGURE V.6



The difference between site and full fuel-cycle energy efficiency is critical in evaluating energy efficiency gains over time. For example, in the residential sector site energy consumption per household was 28% lower in 2011 than it had been in 1987 (see Figure V.7). However, when the losses associated with generating electricity are taken into account, overall primary energy consumption per household in 2011 was almost identical to its level in 1987.

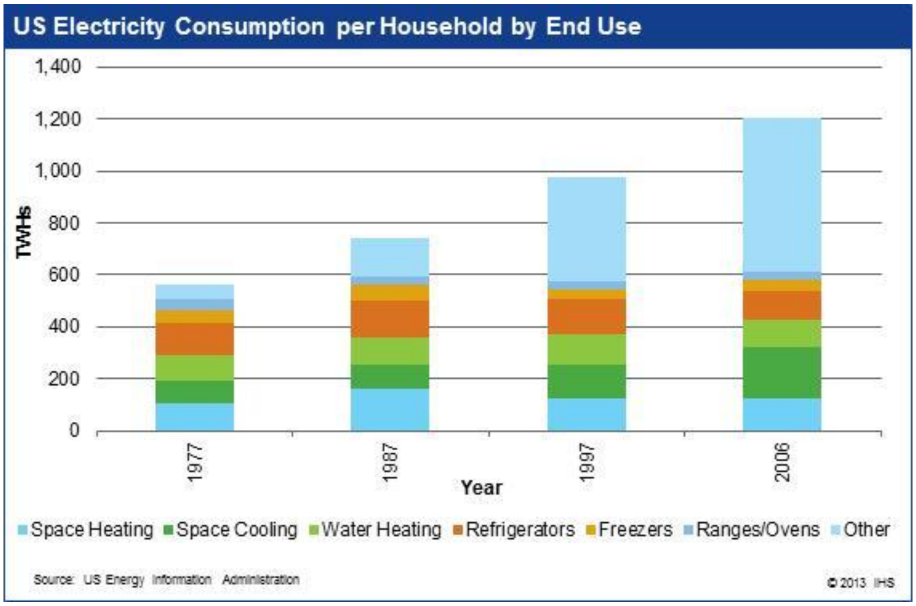
FIGURE V.7



This result is due primarily to the increased share of electricity in total household fuel consumption. Although electricity consumption has declined for almost all applications that were available in 1977--owing to energy efficiency improvements for cooking, lighting, refrigeration, water heating, and space heating and cooling--total electricity consumption per household has grown significantly as other uses of electricity have been devised, such as computers, cell phones, and high-definition televisions (see Figure V.8). EIA has noted that “the number of [new] devices per household have offset efficiency gains in residential electricity use.”[84]

[84] US Energy Information Administration, *Two perspectives on household electricity use*, *Today in Energy*, March 6, 2013, http://www.eia.gov/todayinenergy/detail.cfm?id=10251&src=email.

FIGURE V.8



Components of full fuel-cycle energy analyses

Table V.3 provides the efficiencies of various fuels at various stages of the supply chain in 2007, as estimated by the Gas Technology Institute.[85] Natural gas extraction and processing are each estimated to be about 97% efficient—with approximately 3% of natural gas used in the production process and another 3% in gas processing. Gas transportation and distribution are each about 99% efficient with approximately 1% of natural gas used in transportation and another 1% in gas distribution. As a result, the natural gas supply chain, from wellhead to burner tip is about 92% efficient, using approximately 8% of the natural gas supply to produce, process, and deliver natural gas to end users. Oil and propane are each about 89% efficient for their supply chains.

Electricity production is much less efficient, owing primarily to the energy losses in generating electricity (the conversion process). Conversion losses depend on the mix of generating technologies and their efficiencies. As of 2007, coal-fired power plants were on average less than 33% efficient. That is, more than two-thirds of the energy content of the coal input to a power plant was lost (primarily as waste heat) in the process of generating electricity. Natural gas power plants were more efficient at 42% on average, although many natural gas power plants are more efficient. Overall, given the mix of power plants in 2007 and considering the energy required to produce and deliver fuel to power plants, the energy efficiency of electricity production was only about 32% on a national average. Regional efficiencies would vary considerably depending on the generation mix in the region.

IHS CERA estimates that by 2012 the average efficiency of coal-fired and gas-fired power plants had increased slightly, and more gas and renewable generation had been added to the mix, so that the overall energy efficiency of electricity production had increased to about 40%. With continued efficiency increases and greater penetration of renewable technologies; full fuel-cycle electric generation efficiency is projected to increase to 46% by 2035. Again, regional efficiencies will vary depending on each region's

[85] Marek Czachorski and Neil Leslie, Gas Technology Institute, *Source Energy and Emissions Factors for Building Energy Consumption*, report to the Natural Gas Codes and Standards Research Consortium, Washington, DC, August 2009.

generation fuel mix.

Because of the losses in producing and transmitting electricity to the end user, an electric appliance will today have a full fuel-cycle efficiency that is only about 40% of its site energy efficiency (expected to increase to 46% by 2035). Because the natural gas supply chain is estimated to be 92% energy efficient, the full-cycle energy efficiency of a natural gas appliance will be 92% of its site energy efficiency.[86]

TABLE V.3

Energy Value Chain Efficiencies

Energy Source:	Cumulative Efficiency*	Extraction	Processing	Transportation	Conversion	Distribution
Primary Fuels Used at Burner Tip (2007)						
Natural Gas	91.9%	97.0%	96.9%	99.0%		98.8%
Oil	88.6%	96.3%	93.8%	98.8%		99.3%
Propane	89.3%	95.9%	95.3%	98.6%		99.2%
Electricity Weighted Average 2007	31.9%					
Coal-based	29.3%	98.0%	98.6%	99.0%	32.7%	93.8%
Oil-based	26.5%	96.3%	93.8%	98.8%	31.7%	93.8%
Natural Gas-based	36.7%	97.0%	96.9%	99.0%	42.1%	93.8%
Nuclear-based	29.2%	99.0%	96.2%	99.9%	32.7%	93.8%
Other-based	49.7%				56.0%	93.8%
Electricity Weighted Average 2012	40.2%					
Coal-based	30.7%	98.0%	98.6%	99.0%	34.2%	93.8%
Oil-based	24.5%	96.3%	93.8%	98.8%	29.3%	93.8%
Natural Gas-based	39.7%	97.0%	96.9%	99.0%	45.5%	93.8%
Nuclear-based	29.1%	99.0%	96.2%	99.9%	32.6%	93.8%
Other-based	26.3%	0.0%	0.0%	0.0%	28.0%	93.8%
Renewables-based	93.8%					93.8%
Electricity Weighted Average 2035	46.3%					
Coal-based	31.5%	98.0%	98.6%	99.0%	35.2%	93.8%
Oil-based	26.5%	96.3%	93.8%	98.8%	31.6%	93.8%
Natural Gas-based	41.1%	97.0%	96.9%	99.0%	47.1%	93.8%
Nuclear-based	29.6%	99.0%	96.2%	99.9%	33.2%	93.8%
Other-based	26.3%	0.0%	0.0%	0.0%	28.0%	93.8%
Renewables-based	93.8%					93.8%

*Cumulative efficiency is the product of extraction, processing, transportation, conversion and distribution.
Based on Gas Technology Institute, *Source Energy and Emission Factors for Building Energy Consumption, August 2009.*
Electricity calculations for 2012 and 2035 based on IHS CERA projections.
Source: American Gas Association *Squeezing Every BTU*, January 2012

Because natural gas appliances generally have an advantage over electric appliances in terms of full fuel-cycle efficiency (owing to the very large amounts of energy required to produce and deliver electricity) substituting a gas appliance for an electric appliance should lead to an increase in natural gas consumption, but a decline in total energy consumption. Furthermore, a shift to natural gas from electricity or oil is likely to provide a decrease in emissions of sulfur dioxide, nitrogen oxide, carbon dioxide, mercury and particulates.

[86] Gas Technology Institute, *Source Energy and Emission Factors for Building Energy Consumption*, August 2009.

Full fuel-cycle example: natural gas versus electricity for water heating

When measured only in terms of site efficiency, many electrical appliances themselves appear to be more efficient than gas appliances. For example, a tankless electric water heater is 90-98% efficient in terms of converting electricity into hot water in the home, compared with 80% site efficiency for a tankless gas water heater (see Table V.4). Tankless water heaters have an advantage over conventional water heaters in that about 23% of the energy used by the conventional water heater is used to keep the storage tank water at the desired temperature. Hybrid electric hot water heaters use a heat pump with a site energy efficiency of 220% to keep the storage tank water at the desired temperature. (Heat pumps can have site energy efficiency greater than 100% because the energy used to extract and move heat from outside to inside is less than the heat moved inside.)

When evaluated in full fuel-cycle terms, natural gas appliance efficiencies can be superior to those of electric appliances because of the losses incurred in generating and distributing electricity. For example, when the energy required for generating and transmitting electricity to the home is taken into account, the full fuel-cycle efficiency of the tankless electric water heater falls to about 30%, compared with a full fuel-cycle efficiency of 74% for the tankless gas water heater.

Full fuel-cycle analysis can also be applied to emissions analysis. Full fuel-cycle emissions analyses are likely to show that in many instances natural gas appliances have lower full fuel-cycle emissions than an electric appliance.

Table V.4

Site and Full Fuel-Cycle Efficiencies of New Gas and Electric Water Heaters, 2006
Shipment Weighted Averages
Coefficient of Performance

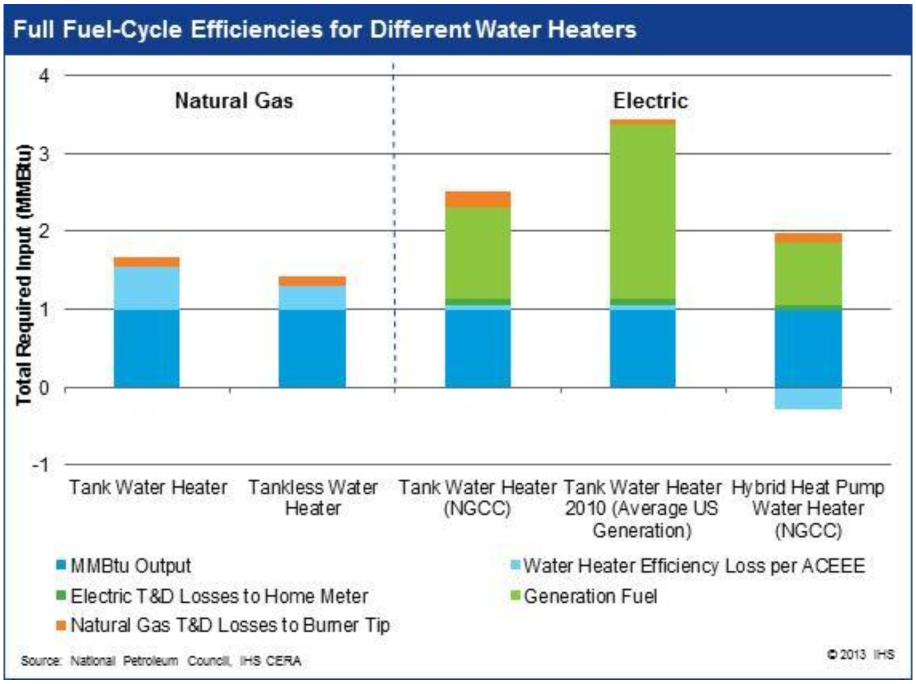
	Site Efficiency	Full Fuel Cycle Efficiency
Natural Gas		
Tank Water Heater	67%	62%
Tankless Water Heater	80%	74%
Electric		
Tank Water Heater	94%	30%
Tankless Water Heater	90-98%	29-31%
Hybrid Water Heater	220% for Heat Pump	70% for Heat Pump
	94% for Standard	30% for Standard

Source:
Appliance Efficiencies from Lawrence Berkeley National Laboratory, EETD/EAD, July 2007.
Hybrid electric water heater efficiency from retailers description of product in 2013.
Review of General Electric, Rheem, Home Depot, Sears and other manufacturers and retailers offerings .
IHS calculations from site to full-fuel cycle use ratios from the Gas Technology Institute.

Figure V.9 compares the total energy required to produce one MMBtu of hot water using natural gas versus electric appliances with different efficiencies and also assuming different fuel mixes in the case of the electric appliances. Despite their greater site efficiencies, most of the electric water heaters require considerably more fuel than the natural gas water heaters when the energy required to produce and distribute electricity is included in the calculation. The figure specifically shows results (in order left to right) for a tank natural gas water heater (65% site efficiency), a tankless natural gas water heater (77% site efficiency), an tank electric water heater (95% site efficiency) that uses electricity produced by a natural gas combined-cycle (NGCC) power plant, an tank electric water heater (95% site efficiency) using electricity produced by the average US generation mix in 2010, and finally a hybrid electric water heater

(134% site efficiency).[87] Only the hybrid electric water heater, which incorporates a heat pump, has a full fuel-cycle efficiency similar to that of a natural gas water heater.

FIGURE V.9



Shifting the paradigm to full fuel-cycle efficiency analysis

Currently most existing building codes and appliance standards are based on site efficiency measurements and ignore the losses associated with producing and delivering energy to the site. One exception is the EPA's EnergyStar building programs that allow comparisons of building energy use based on full fuel-cycle concepts. And in August 2012 DOE announced that it would use full fuel-cycle measures in future energy efficiency standards rulemakings.[88] Some other countries are also adopting full fuel-cycle analysis (see the box "Moving to natural gas for home heating in France").

Moving to natural gas for home heating in France

Last year the French government instituted Réglementation Thermique 2012 (RT2012), requiring new residential buildings to consume less than 50 kWh per square meter of primary energy—about one-fifth of the primary energy consumption of the average household in France. The rule is significant in that it shifted the measurement of efficiency from a site efficiency concept to a full fuel-cycle, or primary energy, efficiency measurement. As a result, many electric technologies are now disadvantaged and many gas technologies are favoured. IHS CERA estimates that around 80% of the new homes currently built to conform to RT2012 are heated with gas and only 5% with electricity—mainly heat pumps.

[87] American Council for an Energy-Efficient Economy.

[88] *Federal Register*, Vol. 77 No. 160, Friday, August 17. 2012, page 49701.

Energy efficiency and cost efficiency

Because of the energy losses incurred in the generation of electricity, it may be possible to increase overall energy efficiency in the United States by substituting natural gas consumption for electricity consumption for uses that can be served by either energy form —such as space heat, water heat, or cooking.

But energy efficiency does not necessarily equate to economic efficiency, which depends on fuel costs and capital costs as well as the energy efficiency of appliances and the thermal integrity of buildings. With the prospect that retail natural gas prices will be significantly lower than retail electricity prices in many regions over the long-term, it is likely that for some applications natural gas will be more efficient than electricity in terms of both energy and cost for many years. The cost efficiency of some natural gas and electric appliances is discussed in more detail in Chapter IV.

The cost of efficiency

Because of the significant gains in energy efficiency of gas appliances that have already taken place, additional energy efficiency gains could be limited for existing appliance stock. More stringent building codes to improve energy efficiency may also increase the cost of saving energy because of higher capital and installation costs of the most energy efficient technologies. Furthermore, given the outlook for relatively low natural gas prices, fuel cost savings have shrunk. As a result, payback periods for natural gas efficiency improvements for existing natural gas applications will be longer than if natural gas prices were higher. However, improving overall energy efficiency can be accomplished by converting some electrical and oil applications to natural gas. As discussed in Chapter IV, in most regions the outlook for an increasingly large divergence between retail natural gas and retail electricity prices can make a conversion to natural gas a cost effective means of increasing energy efficiency for some applications. Furthermore, high retail oil prices relative to retail natural gas prices may make converting from oil to natural gas economic for some applications, particularly in the Northeast.

Not surprisingly, high-efficiency appliances tend to have higher purchase costs than less efficient appliances. A February 2013 survey of dealer websites revealed the prices for various appliances shown in Table V.5.

TABLE V.5

Capital Cost of Natural Gas and Electric Appliances			
	Natural Gas	Electric	Explanation
Water Heater (50 gallon tank)			
High Efficient	$892	$1,199	Hybrid electric (with Heat Pump)
Low Efficient	$399	$349	
Tankless Water Heater			
3 gallons per minute		$399	
5 gallons per minute		$499	
9 gallons per minute	$963		Condensing gas unit is 94% efficient
Space Heating Furnaces/Heat Pumps			
80,000 Btu/hour - 80% efficient	$618 to $908	N/A	Sufficient to heat a home in moderate temperatures
80,000 Btu/hour - 96% efficient	$1559 to $2294	N/A	
120,000 Btu/hour - 80% efficient	$783 to $912	N/A	Sufficient to heat a home in very cold temperatures
115,000 Btu/hour - 96% efficient	$1757 to $2584	N/A	
Heat Pump 2.5 ton, 14 SEER		$1336 to $1645	Sufficient to heat a home in mild temperatures

Source: General Electric Appliance comparison website, Sears Appliance Center website, Home Depot website, and Rheem website

Whether a high efficiency appliance will be cost effective depends on how quickly the higher purchase cost will be offset by savings in energy costs, and whether this payback period meets the objectives of the consumer. The cost analyses presented in Chapter IV suggest that high-efficiency gas appliances often have lower expected total capital and operating costs than their electric counterparts, although these results vary by region and are highly dependent on relative fuel costs. Nevertheless, some consumers prefer low up front costs to low energy costs over the expected lifetime of the appliance.[89] Moreover, the EIA has found that some high efficiency appliances cost more than can be explained by efficiency savings alone. The EIA notes that "efficient models are often bundled with aesthetic or other functional features not related to energy use … that tend to be offered only on premium models, meaning the incremental costs reflect upgrades and options beyond those directly related to efficiency improvement."[90]

The dynamic of lower gas prices and the inherent energy efficiency of existing appliances and buildings presents challenges to the cost effectiveness of new natural gas energy efficiency programs. A broader view may be required that considers the cost of externalities, which are typically excluded from standard regulator-approved cost effectiveness tests and underlying criteria. Such externalities include emissions of sulfur dioxide, nitrogen oxide, carbon dioxide, mercury and particulates. For some efficiency programs to survive, the method of assessing cost effectiveness may need to be expanded to take into consideration externalities including full fuel-cycle and full emissions-cycle benefits when computing costs and benefits.

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[89] US Energy Information Administration, *For appliances, choosing the most cost-effective option depends on several factors, Today in Energy*, May 29, 2013, http://www.eia.gov/todayinenergy/detail.cfm?id=11451&src=email.

[90] US Energy Information Administration, *Incremental costs of higher efficiency can vary by appliance, Today in Energy*, May 28, 2013, http://www.eia.gov/todayinenergy/detail.cfm?id=11431&src=email.

Policy implications of promoting full fuel-cycle energy efficiency programs

The environment of abundant natural gas at moderate cost presents an opportunity to shift the energy efficiency paradigm. State governments, PUCs and gas LDCs can now consider how natural gas can be used to help improve total energy efficiency and reduce overall emissions. Policies that support greater direct use of natural gas should be underpinned by full fuel-cycle energy analysis, full fuel-cycle emissions analysis, and life cycle cost analysis. Use of these tools can identify regions and applications where greater natural gas use will provide societal benefits such as improved energy efficiency, reduced emissions, and economic efficiency.

Inter-fuel competition

A shift to a full fuel-cycle paradigm by definition means that issues surrounding inter-fuel competition need to be addressed. In particular, PUCs will need to assure that there is a level competitive playing field for all forms of energy, and especially between gas and electricity. One critical role for PUCs will be to address gas and electric competition for combination companies that distribute both gas and electricity. Most companies are reluctant to cannibalize their markets by promoting competition between affiliates. However, without such competition, society may not gain the benefits of lower total energy usage and lower emissions. In 2011, combination companies delivered 23.6 Bcf per day of natural gas to 44 million gas customers, a very substantial portion of all gas LDC deliveries and customers.[91]

Any policy bias against promoting increased use of any fossil fuel will also need to be addressed. Gas LDCs may need to educate policy makers on the “green” benefits from a shift to natural gas until cost effective technologies, other than dispatchable gas-fired generation, are developed to balance intraday variations in electricity demand with the intermittency of renewable generation.

Gas LDC cost recovery mechanisms

When existing customers increase their natural gas consumption—for example by replacing an inefficient electric furnace or oil furnace with a high-efficiency natural gas furnace – a gas LDC might not see an increase in earnings, depending on what, if any, efficiency program cost recovery mechanism in place. For example, a gas LDC with a straight fixed variable rate design under which all of its fixed costs are recovered through a fixed customer charge would not see its earnings increase as no new customers were added. This can act as an impediment to societal-wide energy efficiency gains and emissions reductions as well as the adoption of full fuel-cycle energy efficiency standards. PUCs and gas LDCs may want to review, and if necessary update, their efficiency program cost recovery mechanisms to encourage not just site energy efficiency programs, but full fuel-cycle programs. In addition, PUCs and electric utilities may need to review and update electric cost recovery mechanisms to assure that an electric utility can recover its costs if existing customers convert to natural gas service.

[91] IHS Inc. analysis from AGA data.

Extending gas service

Since a shift to a full fuel-cycle perspective may require greater use of natural gas, PUC and gas LDC policies on adding customers and extending service to new markets may need updating to facilitate a shift from site energy efficiency to the full fuel-cycle energy efficiency paradigm. One of the main obstacles for consumers converting from electricity or oil to natural gas are the up front capital costs. Up front costs can include the cost of running a service line to the home from an existing main, the cost of extending a main, and the customer's cost for buying and installing new equipment.

High up front costs can deter a consumer from converting to natural gas, especially if their furnace or water heater does not need immediate replacement. Many potential customers do not have the financial wherewithal to finance a conversion. To overcome this obstacle, gas LDCs may need to establish above-the-line efficiency conversion programs or below-the-line or affiliate conversion financing programs.[92] These programs would finance the conversion costs over a fairly long period allowing the customer to pay for the conversion costs from energy savings so as to not reduce their discretionary income. With many furnaces lasting 20 years and service lines and mains lasting 30 to 40 years, financing over 10 or more years may be appropriate. However, the longer the financing term, the greater the risk to the lender, a risk that the gas LDC will have to be compensated for. Financing over short periods, such as three years, might result in a reduction to the converting customer's discretionary income, not something many consumers will find attractive. Such financing programs will require educating not only prospective converting customers and suppliers of gas furnaces, but most importantly PUCs and other policy makers. Gas LDCs could lease equipment to customers shifting the first cost burden from the prospective customer to the gas LDC. The first cost burden of connection costs could be handled in a number of ways including using a surcharge to cover connection costs over a fairly long period rather than requiring a large up front lump sum contribution in aid of construction.[93] Lower taxes on contributions in aid of construction might be considered as a way to reduce connection costs. Gas LDCs could use anchor shippers to lower per unit cost of new mains improving the economics for a customer converting to natural gas service.

Implications for gas LDCs

State governments, PUCs and gas LDCs should consider how greater direct use of natural gas can help improve total energy efficiency and reduce overall emissions. Policies that support greater use of natural gas should be underpinned by full fuel-cycle energy efficiency analyses, full fuel-cycle emissions analyses, and life cycle cost analyses. Use of these tools can identify regions and applications where greater direct natural gas use should be promoted to realize societal benefits from improved energy efficiency, reduced emissions, and greater economic efficiency. PUC and gas LDC policies on adding customers and extending service to new markets may need updating to facilitate a shift from site energy efficiency to full fuel-cycle energy efficiency paradigm.

Appliance efficiencies have increased markedly in the past four decades and future gains could be limited.

[92] Above the line capital costs and expenses are included in cost of service and used to design regulated rates. Below the line capital costs and expenses mean the gas LDC's shareholders are at risk for these expenses, and depending on the prospective revenues, may deter a gas LDC from pursuing those activities.

[93] A contribution in aid of construction is a one-time payment by a third-party to a gas LDC to reduce its cost of constructing a facility. The third-party is usually the prospective customer.

As new energy efficiency appliance standards and building codes come into effect, the marginal cost of additional savings grows. And with natural gas prices expected to be relatively low for years to come, the payback period for natural gas energy efficiency investments has lengthened.

But a wider perspective gives a different outlook. When considering the efficiency of an entire energy system, low-cost natural gas has decided advantages. As discussed in Chapter IV, new high-efficiency natural gas technologies and a widening gap between retail natural gas prices and retail electricity prices in many regions may give natural gas a competitive edge over electricity for many residential and commercial applications.

Gas LDCs can work with PUCs, policy makers, and other stakeholders to:

- Adopt full fuel-cycle analysis in all energy savings and energy efficiency comparisons. Currently, most existing building codes and appliance standards are based on site-efficiency and ignore the losses associated with producing and delivering natural gas or electricity to the site.

- Identify new opportunities for natural gas to increase overall energy efficiency in a cost-effective manner. Given the expected growing disparity between retail natural gas prices and the retail prices of electricity and oil, it may be possible to increase overall energy efficiency by increasing natural gas use and decreasing the use of more expensive and less energy efficient sources of energy.

- Overcome approaches in many energy efficiency rulemakings which discourage inter-fuel comparisons and result in promoting inefficient technologies, backed originally by site energy efficiency analysis. PUCs will need to assure that there is a level competitive playing field for all energies, but especially between gas and electricity.

- Work with builders, local governments and other stakeholders to encourage builders to base their appliance decisions not on lowest first cost that tend not to be the most energy efficient option, but on full fuel-cycle and life cycle cost analyses.

- Explore the challenge of maintaining the cost-effectiveness, and therefore viability, of natural gas efficiency programs in the present environment of lower natural gas prices. Regulators and gas LDCs will need to review current and best practices in applying cost-effectiveness tests and potentially explore new approaches to evaluating the programs to ensure the full value of these programs are captured. Regulatory support for recognizing societal benefits of increased energy efficiency or reduced emissions will allow gas LDCs to seamlessly deliver efficiency programs to customers well into the future.

- Educate prospective converting and new customers on the economic and environmental benefits of using natural gas. Since most prospective customers are unlikely to convert until their existing furnace or water heater needs replacing, a successful program needs to be targeted at potential converting customers well before they need to replace their furnace or water heater.

- Revisit, and if necessary, update the terms of cost recovery mechanisms such as decoupling, if current mechanisms would act as an impediment to moving to a full fuel-cycle energy efficiency paradigm.

Chapter VI: Gas LDC System Expansion - Regulatory Perspectives

In Brief

- Gas distribution systems typically are expanded only when they satisfy certain economic tests.
- The application of those tests varies among jurisdictions, and often poses obstacles to system expansions that are in fact economic.
- A combination of gas LDC initiatives, regulatory support, and government policy could remove these obstacles, promote economic use of gas, and serve the public interest in increasing full-cycle energy efficiency and reducing full-cycle emissions.

This chapter discusses the regulatory framework for expanding natural gas distribution networks, the current obstacles posed by that framework, and potential changes in policy that could encourage appropriate system expansion.

The role of regulatory policy in system expansion

Gas LDCs move natural gas from the "city gate" (the point of interconnection between the interstate or intrastate pipeline system and the local distribution system) to end users of gas. These end users include homes, businesses, industrial facilities, and in some case electric generating plants. Local distribution service is generally regarded as a natural monopoly, provided most efficiently within a given area by a single company. Accordingly, a gas LDC typically is granted an exclusive franchise to serve a defined service area, subject to regulatory oversight by a state PUC. PUCs (or other public authorities such as municipalities) approve the cost of gas purchased by gas LDCs and the distribution gas costs incurred by gas LDCs in providing gas service to end users. They also approve tariff structures that permit gas LDCs to cover approved costs, including the cost of invested capital. In exercising these functions, PUCs apply broad standards that give them considerable latitude. A typical standard for approving facilities investments is that they be "required by the public convenience and necessity", and for approving prices is that they be "just and reasonable."

Regulatory policy has a major impact on gas LDC growth--and in particular on the expansion of the gas LDC's delivery systems. Gas LDC growth occurs through increased gas sales to existing customers or through connection of new customers. Increased sales to an existing customer generally depend on the customer converting from oil or electric appliances to gas appliances – a topic discussed in Chapter IV. Connection of a new customer, on the other hand, usually requires not only a receptive customer, but also the installation of new distribution facilities. The facilities required may include main lines (the lines that run below the street and carry gas to multiple locations) as well as service lines (the smaller lines that carry gas from the main line to the individual meter). Main line costs vary depending on topological and environmental factors, but average about $1 million per mile. In addition, substantial network expansions may require reinforcement of existing facilities through replacement of undersized main lines, increased pressure tolerances, and strengthened control systems. Connecting new customers therefore is usually far more costly than increasing sales to existing customers. One recent study indicated that a 1% increase in the number of customers raised costs by 0.71% while a 1% growth in total retail deliveries raised costs by only 0.11% - a difference greater than six fold.[94]

Economic tests

As a condition of their exclusive franchise rights, most public gas LDCs have an obligation to extend facilities to serve members of the public who need service. However, that obligation is usually qualified by an economic test specifying that the gas LDC is required to extend its main lines only if the expected revenues from new customers under the existing rate structure meet or exceed the incremental costs of the network expansion.

If a gas LDC finds that expected non-gas commodity revenues from the expansion (i.e., the revenues under the tariff that are intended to cover system investment and operating costs) will not cover its incremental cost of service (system investment and operating costs), the expansion is deemed "uneconomic" and the gas LDC may request that customers provide a CIAC to cover the uneconomic portion. As an example, if the gas LDC can reasonably expect to receive $10 million of non-gas commodity revenues from new customers in a particular area under its existing rates, the first $10 million of its cost of service to expand or extend a line would be considered economic. Any excess over that first $10 million would require a CIAC to reduce cost of service to no more than $10 million.

This approach raises two broad questions of importance, both of which are matters of regulatory policy. The first is how economic costs are determined, and the second is who pays for the uneconomic costs.

Most gas LDC tariffs specify some form of an economic test that compares the cash flow involved in a system extension against a threshold financial standard. Typical metrics are net present value (which must be greater than zero with a discount rate equal to the gas LDC's cost of capital), internal rate of return (which must be higher than the gas LDC's cost of capital), and payback period (which must not exceed a prescribed maximum number of years). Cost levels that fit within these tests are deemed economic; cost levels that do not are deemed uneconomic.

Each of these tests aims objectively to ensure that the costs of expansion are covered by the corresponding revenues generated, but each test contains elements of judgment that can substantially affect its conclusion. To name a few:

- **Load projections**. How is the incremental flow of future revenue calculated? How many new hook-ups are contemplated, and what volumes are expected to be delivered?

- **Timing**. On what schedule are these volumes expected to materialize, and how will that schedule impact discounted cash flows?

- **Risk**. How confident is the gas LDC in its revenue projections? Main-line extensions into unserved areas present greater uncertainties than hook-ups in areas already served by main lines. The appropriate economic discount rate accordingly may be higher.

[94] Mark Newton Lowry, et al., "Statistical Analysis of Public Service of Colorado's Forward Test Year Proposal, Exhibit No. MNL-1", December 17, 2010, p.21 at http://xcelenergy.com/staticfiles/xe/Regulatory/Regulatory%20PDFs/Exhibit_No._MNL-1.pdf .

- **Time horizon**. What span of time does the analysis encompass? Investments occur early; revenues come later. Using a ten-year horizon, for example, to evaluate the economics of an investment that will be used for 40 years or more can significantly understate the economic return. This time-horizon issue arises in all capital-investment analyses, but is particularly problematic for payback-period tests, which by definition disregard economic benefits that may accrue in the long-term.

While these calculation judgments are primarily the responsibility of the gas LDC, over the long-term as successive expansion proposals, rate filings, and CIAC requests pass through the regulatory process, regulatory policy plays a strong role in shaping these judgments, and determines how active a gas LDC will be in seeking system expansions. A regulatory disposition in favor of system expansion is likely to accommodate longer payback periods, longer time horizons, and more flexible risk recognition in establishing tariffs and CIACs.

For reasons discussed in previous chapters, the benefits of substituting gas for oil or electric appliances extend beyond the identifiable savings enjoyed by particular consumers. Gas appliances often make more efficient use of energy than other appliances, and, taking into account the entire cycle of energy conversion, they involve less release of CO_2 and pollutants than appliances fueled by oil or electricity. The public at large therefore benefits from gas conversion in ways that are not fully reflected by individual consumer choices or fully captured by the incremental economics of system expansion. Beneficial externalities of this kind are difficult to quantify, but recognition of them can lead at least to regulatory acceptance of more accommodating frameworks for evaluating incremental economic impact. Conversely, regulatory preference for restrictive economic tests may be an anachronistic legacy of a period like the 1970s or even the years of the past decade when natural gas was considered a scarce resource whose use should be discouraged.

Allocation of non-economic costs

If determining which expansion costs are economic and which are not is the first broad question facing gas LDCs and regulators, the second is how to allocate those costs that are deemed non-economic. Unlike utility services such as power, water, or telephone lines, which are regarded as basic necessities that should be available to all, gas service is generally regarded as discretionary; most gas appliances have substitutes that are feasible for most consumers. It follows that those customers who wish to use gas should bear the cost without benefit of subsidies.[95] Traditionally, PUCs therefore are reluctant to permit tariff increases on existing customers in order to support extension of service to new customers. It is presumed that uneconomic costs of system expansion should be borne entirely by the new customers served through a CIAC targeted to them exclusively.

This presumption is challenged by the idea that increased access to gas appliances brings public benefits in full-cycle fuel efficiency and emissions reduction. Many states have policies supporting energy efficiency, but until recently those policies have focused on improving energy efficiency at the point of consumption, rather than improving the efficient deployment of energy through the full fuel-cycle that accounts for Btus consumed from wellhead to burner tip or coal mine to electrical use. This broader conception of energy efficiency suggests that the public in general benefits from substitution of gas appliance for oil, propane, or electric appliances. (See Chapter V for more detailed discussion). If the benefits of gas LDC system expansion are in fact enjoyed more broadly than simply by the new

[95] See, for example, the comments of the Delaware Association of Alternative Energy Providers before the Delaware Public Service PUC in PSC Docket No. 12-292.

customers served, then gas LDCs may be justified in spreading the costs more broadly.

In some states this view of a broader public benefit has been accepted, and PUCs have allowed gas LDCs to charge existing customers for part of the costs for new lines in unserved, remote areas. Recent legislation in Nebraska would allow for these charges as a means of promoting economic development.[96] North Carolina has spread the cost burden even further, providing taxpayer assistance in some cases for funding otherwise uneconomic line extensions.[97] In the future, there may be more support for taxpayers and existing gas LDC customers to pay for new gas lines in unserved areas.

Strengthening the economics of system expansion

Whatever the standard and calculation method used for analyzing the economics of system expansion, any measures that increase the expected customer load from a given proposed expansion or make that load more certain will improve the project's viability. Such measures fall into several categories:

- **Securing commitments from large anchor customers**. Signing up an industrial customer, a housing development or subdivision, a hospital, or power plant provides a secure base load that reduces the required contribution from other new customers and the risk associated with load projections.

- **Mitigating initial customer charges**. Charging new customers for main-line extensions can discourage the potential growth that over the long term could pay for the extension. Some gas LDCs accordingly have proposed providing new customers a specified number of "free" main-line feet. The cost associated with those free feet is absorbed into the gas LDC's rate base, in the expectation that over time the revenue from new customers will cover the rate-base increment.[98]

- **Amortizing consumer conversion costs**. Gas appliances are often more expensive than electric appliances, although typically they provide superior economic performance over the life of the appliance due to lower energy consumption. For a variety of reasons, even if they recognize the long-term benefits, consumers may be reluctant to incur this higher up front cost. They may lack the financial flexibility to invest today for energy savings in the future.[99] Or they may not be confident that they will remain at the same residence long enough to recapture their initial investment. Gas LDCs can address this resistance to fuel conversion by offering prospective new customers the option to spread the cost of appliance replacement over several years. Such

[96] Legislative Bill 1115 passed in July 2012. *See* http://nebraskalegislature.gov/FloorDocs/102/PDF/Final/LB1115.pdf; and Laura Demman, "Line Extensions for Natural Gas: Nebraska's Experience," NARUC Winter Committee Meetings, February 3, 2013 at http://www.narucmeetings.org/Presentations/Winter2013_Nebraska-LineExtensions.pdf.

[97] *Report of the Public Staff North Carolina Gas LDCs PUC to the Joint legislative PUC on Governmental Operations: Analyses and Summary of Expansion Plans of North Carolina Natural Gas LDCs and the Status of Natural Gas Service in North Carolina,* April 24, 2012, 3-5 at http://www.pubstaff.commerce.state.nc.us/psngas/publications/bireport.pdf.

[98] An unpublished survey by the American Gas Association shows that 49 out of the 83 respondent gas LDCs reported that they offer limited "free" line extensions. UGI's proposed Growth Extension Tariff (Get Gas) in Pennsylvania is another example of a proactive strategy for promoting fuel conversion and gas line extensions. The pilot plan would allocate the cost of line extensions to the group of new customers connected to a new main, imposing a monthly surcharge that new customers can pay over 10 years, avoiding high up front contribution in aid of construction payments.

[99] See, for example, Jerry Hausman, "Individual Discount Rates and the Purchase and Utilization of Energy-Using Durables," *Bell Journal of Economics* 10,1 (Spring 1979): 33-54; and Jeffrey A. Dubin and Daniel L. McFadden, "An Econometric Analysis of Residential Electric Appliance Holdings and Consumption," *Econometrica* 52, 2 (March 1984): 345-62.

payment plans have been used by electric utilities with regulatory approval in many jurisdictions to encourage energy-efficiency investments. A similar mechanism could be employed to encourage new customers to sign up for gas service; both appliance costs and pipeline costs could be amortized over an extended period through charges on gas bills associated with an address rather than an individual customer.[100] Alternatively, an unregulated affiliate of the gas LDC could offer financing that would not be paid through the gas bill but nonetheless could be attractive to a customer by offering longer payback periods than are typically available from commercial lenders.[101]

- **Educating potential customers**. Many potential customers are uncertain regarding the long-term benefits of natural gas. Remembering the price spikes that occurred almost a decade ago, some may believe that reliance on gas is economically risky. Others simply do not have the time or inclination to research the matter and are uninspired to incur the transaction costs associated with signing up for gas service and switching to gas appliances. By providing information to potential customers in an area that is a candidate for system expansion, gas LDCs can raise awareness of the benefits of gas use and inform customers about the long-term prospects for stable gas price.

- **Guaranteeing price stability**. For customers who experienced sharp gas price spikes almost a decade ago, information regarding the abundance of future gas supplies and the prospects for long-term price stability may not provide sufficient reassurance that gas will be an economic fuel choice in the long-term. Unregulated affiliates of gas LDCs in many instances can provide that reassurance by selling the gas commodity to customers directly, taking onto itself the risk of wholesale gas price volatility, and guaranteeing the customer a stable price or at least a narrow band of price variability.

- **Gathering bundled customer commitments**. One alternative to gathering commitments customer by customer is to adopt the “open season” approach used by interstate pipelines that are contemplating system expansions. Under a program proposed in Massachusetts, for examples, the gas LDC would use such a mechanism to assess the level of interest from potential distribution customers.[102] If a sufficient number of commitments were gathered during the open-season period to make a system expansion economic, the gas LDC would be able to proceed with reasonable assurance of cost recovery.

The foregoing measures will help customers understand and act on the basic economics of gas conversion. They will thereby increase gas LDCs’ opportunities for economic system expansion without involving cross-subsidization and without giving gas any advantage over alternative fuels other than the advantages of its inherent characteristics and cost. They are therefore consistent with basic principles of

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[100] Some gas LDCs are currently providing financial incentives. See, for example, the presentations for the New York State Public Service PUC, *Technical Conference, Case 12-G-0297: Proceeding on Motion of the PUC to Examine Policies Regarding the Expansion of Natural Gas Service*, January 9, 2013. NSTAR in Massachusetts has an aggressive outreach program that disseminates information on the substantial benefits for energy consumers who switch from oil to natural gas, and also offers financing arrangements. NSTAR calculates that up front costs for conversion to gas can exceed $14,000 for a household (including the sum of the cost for new heating equipment, new service connection, and new main extension). With associated annual savings of $2,000 on average, however, many customers are willing to make the conversion if gas LDC amortization is available.

[101] Though conversion costs vary, depending on such factors as the age of the heating system, the need for new internal piping, and by location, they often range from $7,000 to $12,000.

[102] See Massachusetts Department of Public Gas LDCs, *Petition of Bay State Gas Company, d/b/a Columbia Gas of Massachusetts, pursuant to G.L. c. 164, § 94 and 220 C.M.R. § 5.00 et seq., for Approval of a General Increase in Gas Distribution Rates Proposed in Tariffs M.D.P.U. Nos. 105 through 139*, D.P.U. 12-25, Order, November 1, 2012, 373-4.

regulatory fairness. They are unlikely to occur, however, without explicit regulatory support.[103] PUCs can encourage these measures in several ways:

- Pre-approving system investments whose economic returns are supported by strong and credible growth projections. Pre-approval lowers the gas LDC's investment risk and makes it more likely to explore and develop system expansion opportunities.
- Endorsing economic tests that account for revenues over the useful life of the investment
- Encouraging gas LDC financing for customer CIACs through such devices as the free-feet mechanism
- Permitting gas LDC or LDC-affiliate financing of conversion to gas appliances
- Promulgating uniform standards that provide gas LDCs a clear and predictable framework for planning and evaluating potential system expansions

Realizing public benefits from expanding gas LDC systems

The public benefits of using natural gas instead of typical alternative fuel sources may justify measures that go beyond removing economic barriers, and that actually promote the use of natural gas. Active promotion of gas at the expense of alternatives lies beyond the mandates of most PUCs, but state and local governments are entitled to make such policy choices, and can promote gas system expansion as part of an overall energy strategy. In pursuit of such a strategy, governments should consider what changes and/or new measures may be appropriate for their jurisdiction:

- Authorizing the PUC to allow system expansion costs to be recovered through general tariffs applied to existing as well as new customers
- Providing explicit subsidies for expansion of gas networks to unserved areas that meet established density criteria. These subsidies could take the form of economic development grants or state-backed bonds.
- Promoting fuel conversion through information dissemination

Several states are currently pursuing policies of this kind.

- In Nebraska, the absence of the pipe network in rural areas has been identified as an obstacle to economic development. Recent legislation encourages collaboration among stakeholders, including state and local governments, economic development groups and gas LDCs. It allows funding for new pipes from local sales tax revenues and surcharges to customers.

[103] In 2012, for example, the New York PUC initiated a proceeding to review existing policies relating to expansion of gas service. State of New York Public Service PUC, *Proceeding on Motion of the PUC to Examine Policies Regarding the Expansion of Natural Gas Service, Order Instituting Proceeding and Establishing Further Procedures*, Case 12-6-0297, November 30, 2012 at http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId=%7B33008B64-79D4-4DD3-B222-442061E06BAE%7D. The PUC expressed the need to revisit its policies on natural gas expansion in view of recent developments in gas markets.

- In New York, St. Lawrence Gas has launched a system expansion using not only a temporary CIAC from new customers, but also funding from county, regional and state governments. These funds include property tax reductions as well as direct grants.[104]

- Mississippi has adopted an explicit policy of encouraging expansion of the state's gas infrastructure in order to draw industry investment and promote economic development. The state's Public Service Commission recently approved a Supplemental Growth Rider permitting one of its gas LDCs to spend up to $5 million annually on system expansion to support industrial projects. These funds can be used to fill the gap between actual expansion costs and "economic" costs. The cost of this supplemental investment is spread across all gas LDC customers, with a permitted rate of return of 12 percent.

- Currently, only about 31 percent of homes in Connecticut have natural gas heat; the typical oil-heat customer spends about $2,650 a year on fuel and the typical gas customer spends just $1,100. The Governor and the legislature believe that fuel conversion will create jobs, make in-state business more competitive, and improve the environment. The Governor's energy plan has set a target of 300,000 new gas customers.[105]

Competing capital needs

A major nationwide concern is the age of old cast-iron or bare-steel pipes, or old plastic pipes, many of which are susceptible to breaks or leaks. The replacement of old pipes is a costly endeavor. One recent cost estimate to replace all pre-1960 pipes in the US is about $150 billion, or $2,100 per customer.[106] It is possible that some PUCs may be limiting their approval of LDC system expansions to serve new customers because of the need for the gas LDCs to make these massive investments via accelerated pipeline replacement programs. It is also possible that some PUCs may be avoiding an even greater increase in gas LDC rates by rejecting a gas LDC's main line expansion plan to serve new customers when the cost of service for the expansion was expected to exceed incremental revenues.

One counterargument may be that the need to replace aging pipe in and of itself presents an opportunity to lower the cost of a system expansion if combined, or rolled up, with a replacement program. As one example, an old 12-inch main might be replaced with a new 16-inch main substantially increasing capacity, with a substantial portion of the cost being charged to the replacement program. Although such opportunities may be limited, they are likely to create lower cost expansions and should be sought out as potentially attractive opportunities.

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[104] *See* Enbridge St. Lawrence Gas, "System Expansion to Franklin Country", presentation at New York State Public Service Technical Conference, Case 12-G-0297, January 9.

[105] *See* http://articles.courant.com/2012-10-05/business/hc-energy-plan-1005-20121004_1_natural-gas-energy-efficiency-water-heaters.

[106] *See* Rocco D'Alessandro, "Pipeline Safety: Planning for a Safer Future," NARUC 122nd Annual Conference, November 2010, 9.

Implications for gas LDCs

Traditional tests and policies relating to expanding gas distribution systems pose unnecessary and uneconomic obstacles. Gas LDCs need to take a leading role in promoting a more receptive environment for system expansion, but they cannot accomplish that task on their own. Regulatory and legislative support is also required.

- With concerns subsiding about natural gas availability and price, there is a clear justification for PUC policies that support distribution system expansion.
- State governments and PUCs should adopt policies that not only promote site energy efficiency, but also promote analyses that use full fuel-cycle energy efficiency, full fuel-cycle emissions standards, and full cycle costs.
- PUCs should review whether long standing rules are incompatible with current regulatory objectives and conditions in the natural gas sector, and if so, build partnerships between customers, builders, utilities, economic development agencies to work through the challenges.
- PUCs and gas LDCs should re-examine economic tests used for evaluating line expansion investments.
- PUCs and gas LDCs should review options that may ease the burden of high up front costs on prospective customers while protecting both existing customers and competing fuel suppliers.

Chapter VII: Natural Gas in the Industrial Sector

In Brief

- US industrial gas demand is reversing a long-term decline in response to the growing availability of low-cost natural gas and NGLs. The competitive position of certain domestic gas-intensive industries is improving, leading to a wave of planned capacity expansions.
- Although many industrial facilities have direct access to interstate and intrastate pipeline deliveries and therefore wholesale purchases, some will benefit from gas LDC service. IHS CERA estimates that gas LDCs could realize over 2 Bcf per day of incremental industrial load by 2035.
- The most active industry pursuing growth in the United States is chemicals, which is expected to invest $135 billion in new facilities and to increase its natural gas use by as much as 3 Bcf per day by 2035. Nearly 0.6 Bcf per day of this incremental demand could be served by gas LDCs. Driven by arbitrage opportunities with petroleum, world-scale gas-to-liquids (GTL) plants may be developed, but gas LDCs are unlikely to serve these loads.
- Food, primary metals, and non-metallic minerals will likely increase their gas consumption as long as end-use markets and economic conditions allow. Natural gas use in petroleum refining and ethanol production is expected to decline.

Once the largest gas-consuming sector, industrial gas demand has been overtaken recently by power generation, which accounted for 36% of total US gas consumption in 2011 versus 28% for the industrial sector. Industrial gas consumption declined for two decades as a result of increasing energy efficiency, high gas prices in the years before the Shale Gale, and slow growth in industrial production for the most gas-intensive industries, many of which were hit hard by the Great Recession. Nevertheless, this situation is reversing due to the drop in natural gas prices. As industrial companies have become convinced of the durability of lower natural gas and liquids prices, they have increased planned investments in the United States.

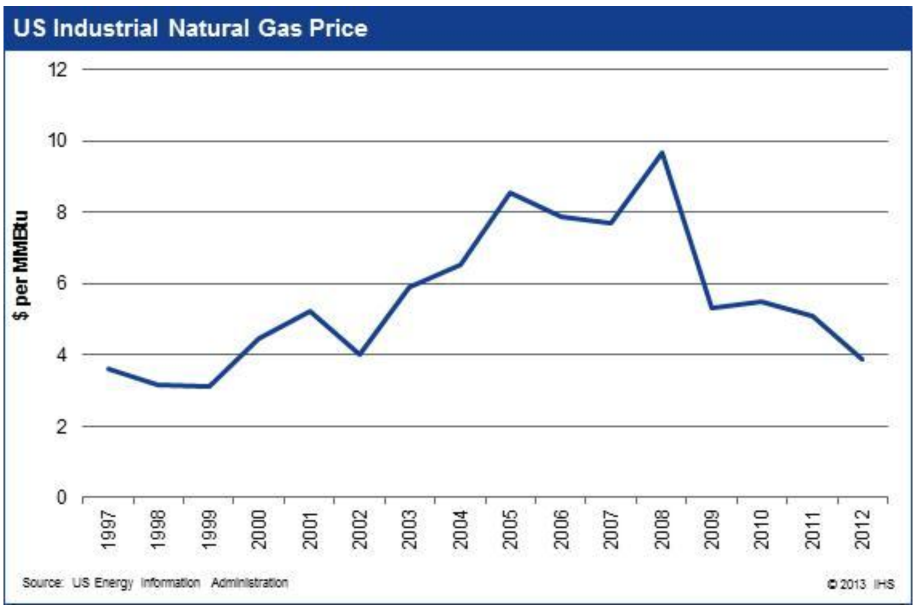
The industry most actively pursuing growth in gas consumption in its US operations is chemicals, especially nitrogenous fertilizers and methanol. However, the food processing, primary metals, and non-metallic minerals industries also expect to benefit.

Although many facilities will have direct access to interstate and intrastate pipeline deliveries, some will benefit from gas LDC service. These facilities may also provide opportunities to expand gas LDC networks by serving as anchor tenants, thereby helping reduce the costs of system expansion.

Chemicals

Chemistry is the foundation of a broad range of downstream industries, including automotive, agriculture, buildings and construction, pharmaceutical, transport, textiles, and many others. Natural gas plays a key role, both as a feedstock for the production of several major petrochemical products, and as a major source of energy required to run the various manufacturing sites. America's abundance of shale gas is driving growth in the production of plastics, pharmaceuticals, fertilizers and other petrochemicals. This has led to lower average gas prices for industrial users (see Figure VII.1). In addition, much of the new supply of unconventional gas has turned out to be rich in natural gas liquids, resulting in surging ethane supplies. Ethane is a key feedstock for many petrochemicals. Its lower cost has given ethane-based domestic chemical production a large advantage over naphtha (a crude oil derivative) as a petrochemical feedstock. Capacity expansion is also being planned in ammonia and methanol, industries that use natural gas directly as a feedstock. With gas now available at a fraction of the energy-equivalent price of oil, the United States could easily become one of the world's lowest-cost petrochemical producers.

FIGURE VII.1

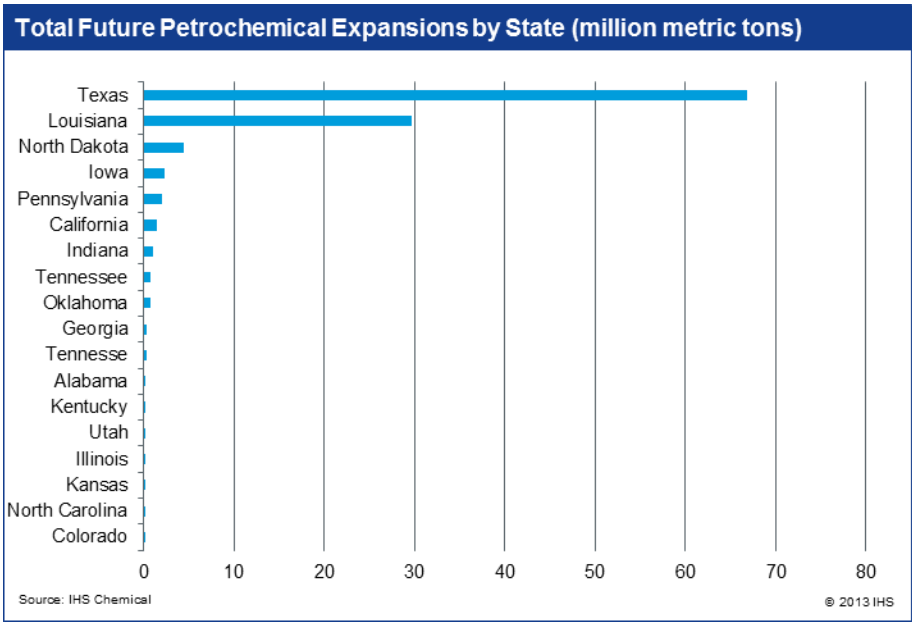


Because about 75% of the cost of producing these petrochemicals and plastics is related to the cost of energy-derived raw materials, the price of oil versus natural gas plays a key role in defining where new capacity is built. The lower cost of domestic gas means that the United States now has a clear competitive advantage, marking a complete turnaround from the situation just a few years ago. The United States was a major petrochemical producer until the late 1990s, after which it lost competitiveness as a result of high oil and gas prices. Many US chemical plants closed down, as new capacity was built in the ethane-rich Middle East and in demand-rich China. The United States saw over 40% of its ammonia fertilizer capacity and 85% of its methanol capacity shut down between 1999 and 2006, and it became a large importer of both products. However shale gas-derived feedstock, which is now available at a fraction of the cost of oil-based feeds, has shifted the scenario in favor of US producers. New investments are expected to back out most of those imports.

IHS estimates that by 2035 as much as $135 billion will have been invested in new chemical, plastics and related derivative manufacturing facilities totaling 110 million tons of additional capacity in the United States. In our view, domestic ethylene and polyethylene production will be the major beneficiaries of the new competitiveness, with a total of 32.6 million tons of capacity additions by 2035. Other chemical products that will see significant growth include ammonia, methanol, and chlor-alkali/vinyl.[107]

Based on announced project plans, historical industry growth patterns and discussions with producers, IHS estimates that the vast majority of the capacity to be built will be located in Texas and Louisiana (see Figure VII.2).

FIGURE VII.2

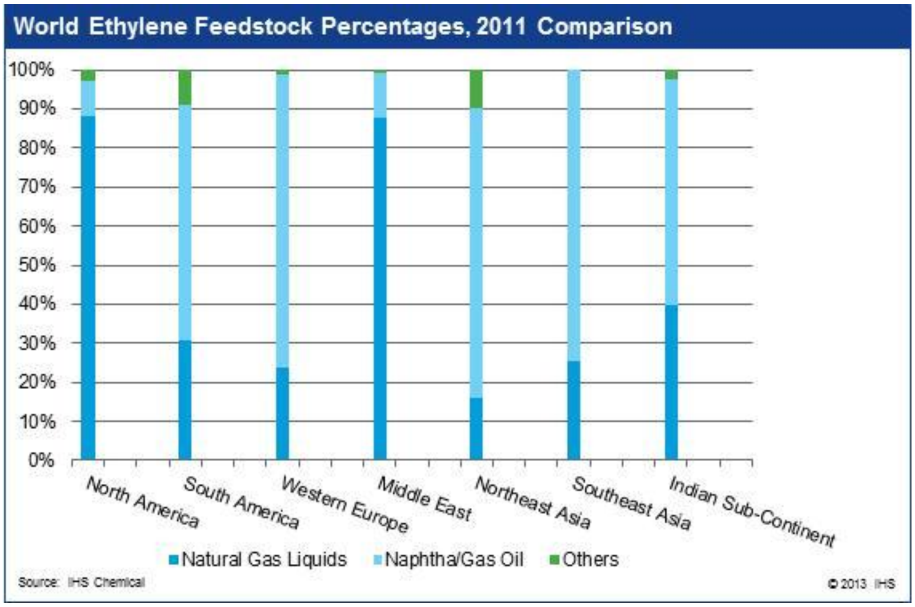


Ethylene

Ethylene is the petrochemical with the largest production, both domestically and globally. Its importance relies on the fact that it is a key raw material for many polymers and other chemicals, such as polyethylene, polyvinyl chloride (PVC), and polyethylene terephthalate (PET). These products are used in a wide variety of industrial and consumer markets such as packaging, transportation, electronics, textiles, construction materials, consumer chemicals, coatings and adhesives. The production of ethylene in the United States is heavily dependent on NGLs (including ethane, propane, and butane), which account for 60% of the cost of production. Today, more than 80% of the ethylene produced in North America is derived from these NGLs, whereas in the rest of the world (except the Middle East) naphtha from crude oil is the key feedstock (see Figure VII.3).

[107] Due to the rapidly changing business environment in the chemical industry, it is difficult to capture the most up-to-date dynamics in the marketplace. In presenting projections of future capacity, trade, supply and demand volumes, IHS Chemical essentially states what we believe to be the most probable future scenarios as of the date of publication. We have applied our best judgment as to which planned facilities have the best chance of going through after carefully modeling supply/demand patterns to see how much new domestic capacity the market can accommodate.

FIGURE VII.3



The price differentials between North American NGLs and global oil feedstocks based on crude oil (i.e., naphtha) now provide a profound and sustainable competitive advantage to the North American petrochemical industry that is expected to persist for decades. Today, the estimated US weighted average ethane cost is less than one-half the cost of ethane in Northeast Asia and Western Europe (see Figure VII.4). The Middle East and Alberta ethane costs are the lowest in the world.

To date, announcements have already been made to expand or build new production facilities in the United States that are capable of producing well over 9 million metric tons per year of ethylene based on ethane feed. The natural gas usage from these new investments is projected to exceed 0.6 Bcf per day by 2035.

As a result of their confidence in an extended period of abundant low-cost NGL feedstocks, chemical producers have already signaled their intentions to increase capacity, reversing the trend of closing plants in the United States since the last new unit was completed in 2001. Chevron Phillips Chemical Company, ExxonMobil Chemical Company, Formosa, Shell Chemical, and the Dow Chemical Company among others, are all building new ethylene plants in the United States, and several producers are expanding or restarting their current facilities, including Ineos, The Williams Companies, LyondellBasell, and Westlake Chemical (see Table VII.1).

FIGURE VII.4

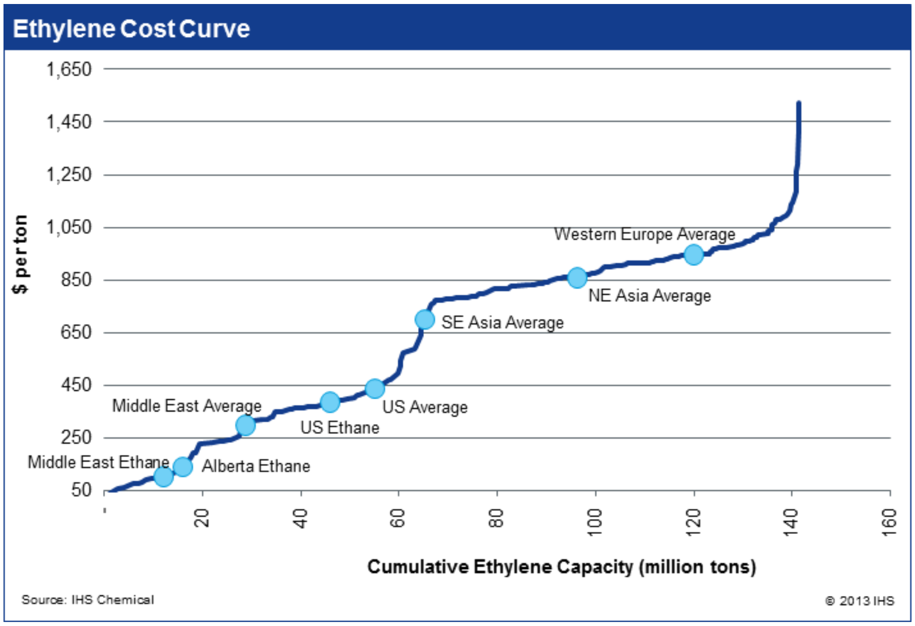


TABLE VII.1

Announced & Generic Plant Ethylene and Derivative Expansions - United States				
Thousand Metric Tons				
Company	**Location**	**Startup**	**Ethylene**	**Total Polyethylene**
Dow (Restart)	Taft, LA	1Q 2013	386	
Equistar	La Porte, TX	4Q 2013	385	
Williams/SABIC	Geismer, LA	4Q 2013	272	
Eastman	Longview	4Q 2013	90	
BASF/Fina	Port Arthur, TX	2Q 2014	180	
Westlake	Lake Charles, LA	4Q 2014	183	
Equistar	Various	4Q 2014	136	
FPC USA	Pt. Comfort, TX	4Q 2016	800	300
ExxonMobil	Baytown, TX	4Q 2016	1,500	1,300
Chevron Phillips	Cedar Bayou, TX	2Q 2017	1,500	1,000
Dow	Freeport, TX	4Q 2017	1,500	1,000
Shell	*Monaca, PA*	*2018*	*1,000*	*700*
Oxy	*Ingleside, TX*	*2018*	*550*	
Sasol	*Lake Charles, LA*	*2019*	*1,400*	*1,000*
Total			**9,882**	**5,300**

Note: Italicized are IHS Chemical generic plants; others are early stage company announcements.

Ammonia

Lower natural gas prices also support investment in the agricultural chemical industry. There are major opportunities to replace imports of fertilizers, while gas feedstock prices also make US fertilizers more competitive internationally. The North American fertilizer segment uses natural gas as a key feedstock for the production of ammonia and its derivatives: urea, ammonium sulfate, and ammonium nitrate. Anhydrous ammonia is used directly as a fertilizer and also as a feedstock in the production of other fertilizers.

Operating rates in 2013 for US ammonia producers are estimated to be around 90% of capacity. However, production volumes this year are expected to satisfy only 65% of domestic demand, with the remaining 35% being provided by imports, primarily from low-cost South American producers, mainly Trinidad. Lower natural gas prices have increased the profitability of domestic production, resulting in the restarting of some plants. In addition, the expected returns on investment are high enough to justify new builds on the US Gulf Coast, and in strategically located areas close to both crop production and shale gas deposits, taking advantage of savings in logistics cost to improve returns.

Consequently, while already there is a positive effect on US fertilizer production, the impact is only starting to be felt. New world scale plants are being built on the US Gulf Coast by CF Industries, Dyno Nobel, and Mosaic (see Table VII.2). Other new plants being built close to the Midwest market include those by OCI in Iowa and CHS in North Dakota. Agrium is also planning a world scale ammonia, urea and urea ammonium nitrate (UAN) complex in the central United States, although progress on the engineering design of the new plants has recently been postponed while the company looks for partners to share the costs. To date, announcements have been made to expand or build new US production facilities that are capable of producing over 6 million metric tons per year of natural gas based ammonia, and another 6 million metric tons per year of urea. By 2035, IHS Chemical expects this total to reach or exceed 8.7 million metric tons. Each metric ton of ammonia uses about 30.5 MMBtu of natural gas feedstock, so the total natural gas usage from these new investments is projected to approach 260 Bcf per year or about 0.7 Bcf per day by 2035 (excluding derivatives).

TABLE VII.2

Announced & Generic Plant Ammonia and Urea Expansions - North America

Thousand Metric Tons

Company	Location	Country	Startup	Ammonia	Urea
OCI Beaumont (Restart)	Beaumont, TX	United States	4Q 2011	250	
Terra Industries	Woodward, OK	United States	1Q 2011		130
PCS Fertilizer (Restart)	Geismar, LA	United States	4Q 2012	500	285
Rentech	East Dubuque, IL	United States	4Q 2012	70	18
US Nitrogen	Mosheim, TN	United States	1Q 2014	60	
CF Industries	Donaldsonville, LA	United States	4Q 2015	800	1,200
CF Industries	Port Neal, IA	United States	4Q 2015	770	1,223
Agrium Inc.	Borger, TX	United States	2016	120	640
Dyno Nobel	Waggaman, LA	United States	2016	750	
OCI	Wever, IA	United States	2017	760	1,000
Mosaic	*TBD, LA*	*United States*	*2016*	*700*	
CHS, INC	Spiritwood, ND	United States	2017	760	760
Agrium Inc.	*TBD*	*United States*	*2017*	*760*	*1,100*
Total				**6,300**	**6,356**

Note: Italicized are IHS Chemical generic plants; others are early stage company announcements.

Methanol

Another industry that stands to benefit from the natural gas boom in North America is methanol. Natural gas is used directly as a feedstock to make methanol in most regions of the world, although coal also is used for a significant amount of production in China. Global methanol demand of around 65 million metric tons will more than double over the next ten years, driven by investments in China for methanol-to-olefin or methanol-to-propylene (MTO/MTP) production and vehicle fuel uses (direct methanol addition into gasoline). Traditional end uses such as in the production of formaldehyde and acetic acid will also continue to grow.

Prior to 2006, the United States was the marginal producer of methanol globally, owing to relatively high natural gas prices. Between 1999 and 2006, the US methanol market consolidated over 80% of its nameplate capacity. However, gas prices are now expected to allow significant margins in the United States, even in slack periods.

IHS expects nearly 7 million metric tons of methanol capacity to be built in Texas and Louisiana by 2016 (see Table VII.3). Except for the Lake Charles plant, which will be petroleum coke based, all of the new methanol capacity will use natural gas as feedstock. Each metric ton of methanol uses nearly 35 MMBtu of natural gas, so the total natural gas usage from these new methanol investments is projected to exceed 240 Bcf per year or nearly 0.7 Bcf per day by 2035 (excluding derivatives).

TABLE VII.3

Announced Methanol Expansions - United States

Thousand Metric Tons

Company	Location	Startup	Methanol
OCI Beaumont	Beaumont, TX	2012	750
Lyondell MOH jv	Channelview, TX	4Q2013	780
Methanex	Geismar, LA	2014	1,000
Celanese	Clear Lake, TX	2015	1,300
Leucadia	Lake Charles, LA	2016	1,280
Southern Louisiana	St. James Parish, LA	2016	1,850
Total			**6,960**

Note: early stage company announcements.

Chlor-alkali/vinyls

The chlor-alkali industry produces chlorine and caustic products that are in turn used in a wide range of industries, including vinyls and silicones, pulp and paper, aluminum, and textiles. The key cost driver for chlor-alkali production is electricity, the cost of which will benefit from low-cost natural gas. Large scale producers in North America derive electricity from natural gas through co-generation. US Gulf Coast chlor-alkali producers have a significant cost advantage over other regions that is expected to persist over the long-term. Even today, IHS estimates that a US producer has a $150 per production cost advantage over a European producer using the same production technology. But the advantage does not stop with electricity. Because the feedstocks derived from gas are significantly lower cost than their alternatives, the cost of ethylene produced in the region also provides an opportunity to compete favorably on a global basis. Chlorine is not directly exportable and needs to be transformed into a derivative to become a global commodity, but caustic soda (chlorine’s co-product) is a classic global commodity.

The chlorine and caustic soda cost advantage in the US has rekindled the idea of investment along the US Gulf Coast to export derivatives to the world. Particularly, there is a huge shift underway in the vinyls chain. Chlorine and ethylene are used to make ethylene dichloride (EDC), vinyl chloride monomer (VCM) and ultimately PVC. PVC is used to make vinyl windows and siding, as well as PVC pipe all of which are used mainly in the construction industry.

The effect on the PVC industry has been remarkable. At a time when domestic demand for PVC is weak due to the recession and still recovering public and private construction, PVC producers have been afforded a new level of cost competiveness, and exports now are a critical component of all PVC produced in the US. In fact, US exports of PVC in 2011 represented 36% of domestic production, compared to only 12.5% in 2007. As the PVC advantage has developed, so too has a better position for exports of PVC intermediate products from North America. New projects have been announced along the chain, including intermediate product expansions and PVC expansions.

By 2014, a number of world-scale chlor-alkali plants will be added to the capacity base in the US (see Table VII.4). All will take low cost chlorine and combine it with low cost ethylene to provide low cost exports in the vinyls chain. The total natural gas usage from these new chlor-alkali investments is projected to exceed 80 Bcf per year or 0.2 Bcf per day by 2035.

TABLE VII.4

Announced Chlorine Expansions - United States				
Thousand Metric Tons				
Company	**Location**	**Startup**	**Chlorine**	**Caustic**
Shintech	Plaquemine, LA	2011	482	530
FPC	Point Comfort, TX	2012	175	193
Dow/Mitsui	Freeport, TX	2013	800	880
Westlake	Geismar, LA	2013	350	385
OxyChem	New Johnsonville, TN	2013	183	201
Others		Various	18	20
Total			**2,008**	**2209**

Note: early stage company announcements.

Incremental petrochemical demand for natural gas

The petrochemical industry could add as much as 2 Bcf per day to its natural gas usage by 2020, and nearly 3 Bcf per day by 2035 (see Table VII.5).[108] This is an increase of more than 50% from the industry's gas usage in 2011. Over half of the additional natural gas demand is likely to be located in Texas, and another 30% or so in Louisiana. Feedstock use, for ammonia and methanol, will account for nearly half of the increased natural gas demand (see Table VII.6).

[108] Incremental natural gas demand from the petrochemical industry in Tables VII.5, VII.6, VII.7 and VII.8 is estimated using cumulative projected capacity additions, annual plant operating rates and process economic assumptions by chemical product from the IHS Process Economics Program Year 2012 – all provided by IHS Chemical. Behind city gate estimates rely on AGA state-level aggregate data for 2011.

TABLE VII.5

Petrochemical Industry Incremental Natural Gas Usage by S				
MMcf per day				
State	2012	2015	2020	2035
Alabama	-	3.5	7.5	7.9
California	9.5	9.6	33.9	35.6
Colorado	0.5	0.5	0.6	0.6
Georgia	3.4	8.7	8.7	9.0
Iowa	-	-	70.1	114.4
Illinois	0.1	9.4	9.5	9.8
Indiana	-	-	-	84.5
Kansas	0.1	0.1	0.1	0.1
Kentucky	-	0.4	0.4	0.4
Louisiana	17.6	201.5	566.3	890.1
North Carolina	0.2	0.2	0.2	0.2
North Dakota	-	-	147.2	151.5
Oklahoma	9.6	9.9	10.0	52.6
Pennsylvania	-	-	42.1	45.3
Tennessee	3.2	29.7	31.6	34.4
Texas	66.2	351.5	1,122.9	1,688.6
Utah	2.1	3.9	4.2	4.6
Total	**112.4**	**628.8**	**2055.2**	**3129.6**

Source: IHS Chemical

TABLE VII.6

Petrochemical Industry Incremental Natural Gas Usage by Type				
MMcf per day				
Type	2012	2015	2020	2035
Electricity	32.8	138.7	342.4	554.8
Feedstocks	55.1	336.2	1,004.1	1,354.4
Fuel	8.4	98.2	518.8	920.8
Steam	16.1	55.8	190.0	299.6
Total	**112.4**	**628.8**	**2,055.2**	**3,129.6**

Source: IHS Chemical

Based on current patterns of gas deliveries by gas LDCs to the industrial sector, IHS estimates that gas LDCs will supply only about one-sixth of the total increment to natural gas use from the chemical industry, or about 0.6 Bcf per day of new deliveries by 2035 (see Tables VII.7 and VII.8).

TABLE VII.7

Petrochemical Industry Incremental Natural Gas Usage Behind City Gates b				
MMcf per day				
State	**2012**	**2015**	**2020**	**2035**
Alabama	-	2.1	4.5	4.8
California	7.6	7.7	27.2	28.6
Colorado	0.3	0.3	0.3	0.4
Georgia	1.7	5.4	5.4	5.6
Iowa	-	-	44.0	71.8
Illinois	0.1	6.6	6.7	7.0
Indiana	-	-	-	78.8
Kansas	0.0	0.0	0.0	0.0
Kentucky	-	0.1	0.1	0.1
Louisiana	0.4	4.7	16.5	26.4
North Carolina	0.2	0.2	0.2	0.2
North Dakota	-	-	92.7	95.4
Oklahoma	5.0	5.1	5.2	27.6
Pennsylvania	-	-	30.9	33.2
Tennessee	0.8	10.5	11.0	11.8
Texas	7.5	39.4	123.5	184.6
Utah	1.2	2.2	2.4	2.6
Total	**24.9**	**84.5**	**370.7**	**578.8**

Source: IHS Chemical

TABLE VII.8

Petrochemical Industry Natural Gas Usage Behind City Gates by Type of Use				
MMcf per day				
Type	**2012**	**2015**	**2020**	**2035**
Electricity	6.7	15.1	44.8	60.2
Feedstocks	10.3	42.8	192.8	336.1
Fuel	0.9	8.9	76.1	115.6
Steam	6.9	17.6	56.9	66.9
Total	**24.9**	**84.5**	**370.7**	**578.8**

Source: IHS Chemical

Petroleum refining

Petroleum refining uses highly energy-intensive processes to transform crude oil into sophisticated petroleum products that serve a variety of markets. According to EIA, petroleum refining is the second largest user of natural gas in manufacturing (after chemicals). This industry used about 2.4 Bcf per day of natural gas in 2010, primarily for process heat and boiler fuel. The industry also uses natural gas as feedstock to produce hydrogen, either on site at the refining facility or by a merchant hydrogen producer for desulfurization and cracking.

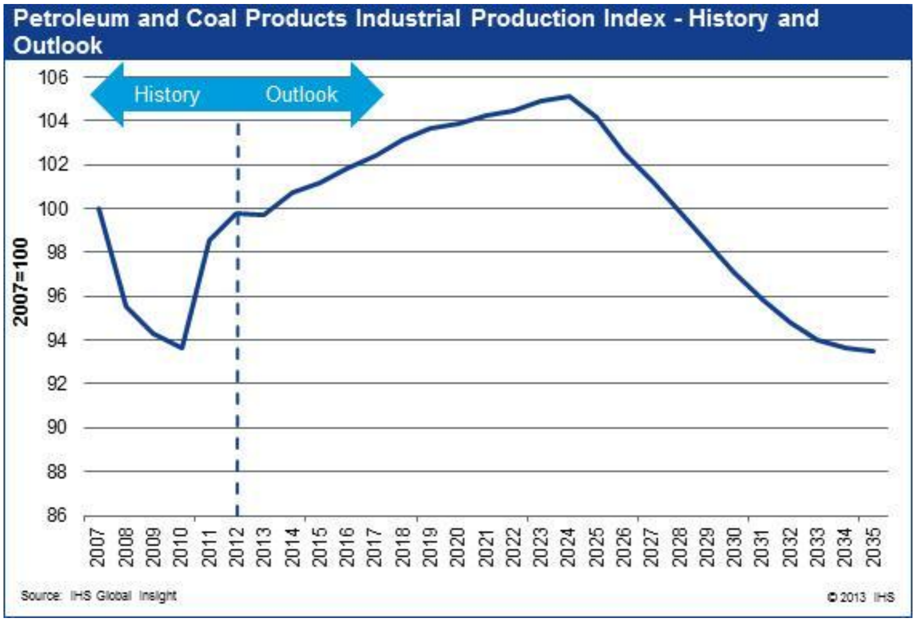
Continued use of natural gas in petroleum refining will depend on industry growth and efficiency of fuel use. As crude oil input to US refineries becomes lighter and sweeter, as discussed below, natural gas use is likely to diminish.

The biggest concern of petroleum refiners, aside from recession-related decreases, has been flat to declining domestic demand for petroleum products. All major refined products registered demand losses in 2012, with total US refined product demand down by over 340,000 barrels per day (bd), or -1.8% per year. Higher fuel efficiency standards, incentives for alternative-fuel vehicles and expanded use of biofuels are affecting demand for petroleum fuels. In addition, the US fleet composition is increasingly leaning towards smaller light-duty cars and vehicle-miles traveled (VMT), a measure of travel activity, have leveled off. US gasoline demand has been on a downward trend since 2005 due to a slower growth in VMT, gradual increase in fuel efficiency, and an increase in alternative fuels like ethanol. The slower economy has impacted VMT growth even further as people have travelled less for vacation, work, and other activities. Higher oil prices have also impacted VMT and new vehicle fuel economy as consumers look for ways to cut spending on gasoline. US gasoline demand fell by 50,000 bd (-0.6%) in 2012 and it is projected to remain flat in 2013 with some growth (23,000 bd) returning in 2014 as economic conditions improve.

Besides supplying refined products to the domestic market, US refineries are well positioned to serve international markets where demand is growing. Since a large share of the refining capacity is located on the Gulf Coast with marine access, Latin America has become the main US refined products export partner also due to proximity. For US refiners, the alternative to supplying output to export markets is lower plant utilization rates and contraction of existing capacity, and this production outlet is anticipated to grow in importance over the next decade and beyond. IHS Global Insight projects that petroleum refining production will expand until 2024 at 0.4% per year, before beginning a gradual decline as consumer spending for refined petroleum products plummets due to increasing automotive efficiency and fewer miles traveled (see Figure VII.5).

Given the output projections for the refining industry, if natural gas consumption per unit of output were to remain constant at 2010 levels, the industry's natural gas consumption would total just over 2.5 Bcf per day in 2035. But another important consideration suggests that natural gas consumption in petroleum refining will decline in coming years as the quality of crude oil input to refineries changes. Technological advances in tight oil exploration and production in the Eagle Ford and Bakken oil plays in the last few years have brought increasing quantities of lighter, sweeter crude feedstocks to refiners, displacing heavier crude oil imports from Mexico, Venezuela and Canada. As heavier crudes require significantly more natural gas per barrel to process than lighter crudes, a continuation of this trend will reduce refinery consumption of natural gas.

FIGURE VII.5



This trend could reverse if the industry grows faster than projected, which could happen with higher exports, faster population growth, faster economic growth, and slower gains in automotive fuel efficiency. In addition, continued low penetration of alternative-fuel vehicles and failure to develop commercial-scale quantities of next-generation biofuels could turn customers back to petroleum-based products. Removing the Renewable Fuel Standard and the associated mandatory blending of ethanol into gasoline could increase petroleum demand by nearly 1 million bd if all ethanol were displaced. This in turn would increase refinery use of natural gas. However, eliminating the ethanol requirement would also eliminate 1 Bcf per day of natural gas used in ethanol production.

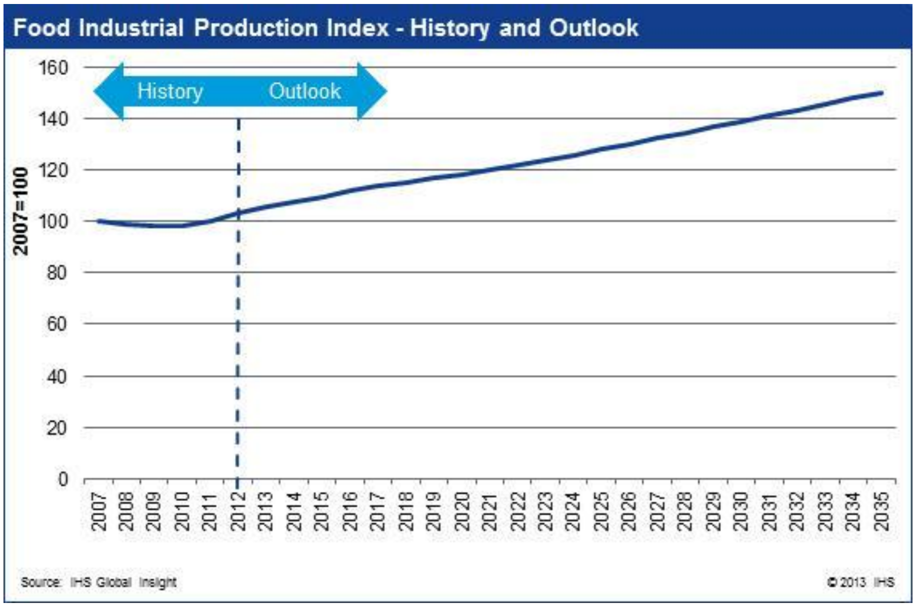
Gas LDCs are unlikely to benefit from any growth that might occur in refinery use of natural gas. Much of the US refining infrastructure is concentrated along the Gulf Coast (Texas and Louisiana together host 24% of all major facilities), California (9%) and Illinois (6%), where a significant portion of the natural gas is obtained directly from pipelines. This is especially true in Texas and Louisiana, where almost 98% and 90% of industrial natural gas consumption, respectively, is delivered from sources other than gas LDC networks.

Food industry

The food industry is the third largest user of industrial natural gas after chemicals and petroleum refining (1.4 Bcf per day in 2010) and one that has suffered the least from the recent US recession, both in terms of production and natural gas usage. The major uses of natural gas in this sector are for food processing, where the majority of thermal energy is provided by natural gas–fired boilers, as well as for space and water heating. Processed foods encompass a vast array of items including washed and packaged fruits and vegetables, canned and frozen goods, breakfast cereals, crackers, cookies, fruit drinks, carbonated beverages and high-end prepared deli dishes. Demand for food is not very responsive to changes in disposable income of the US consumer.

As a result of efficiency improvements which have reduced energy intensity, growing output of processed foods has not led to significant growth in natural gas usage. IHS Global Insight expects food industry output to grow by 1.6% per year through 2035 (see Figure VII.6). Assuming no change in natural gas consumption per unit of output, this suggests that the food industry's natural gas use will rise from 1.4 Bcf per day in 2010 to about 2.1 Bcf per day in 2035.

FIGURE VII.6



For any this sector's natural gas demand in this sector to increase faster, consumption of processed foods has to increase dramatically, and the United States is already one of the global leaders in packaged food consumption per person. This could happen due to population growth, but would be more likely to happen as a result of lifestyle changes, which occur more gradually. For instance, if the US economy grows robustly beyond its long-term expected rate and structural unemployment declines, people will have even less time or opportunity to cook with fresh ingredients, substituting for fresh food with various processed foods for convenience. Another factor that could drive demand for processed foods is the cost of fresh produce – any perceived price increases in basic ingredients could lead to substitution.

Proximity to the end-user base (US population centers) is only one of the drivers for the location of major food processing plants. Supply chain, logistical and workforce issues are other important considerations for food manufacturers. While the East North Central region is home to about 15% of the US population, it has a disproportionately high share of food processing facilities that are high consumers of energy, nearly 21% of the total for the nation.[109] The greater Chicago metropolitan area (extending into Indiana and Wisconsin) is a major hub for air, rail and trucking transportation modes, which explains the concentration of food facilities in that area. Gas LDCs cover 72% of Illinois's industrial gas needs and

[109] IHS Major Industrial Plant Database.

over 90% of neighboring Wisconsin and Indiana throughput, where 173 sizeable food & kindred products plants (8% of the US total) are located. There are many food facilities located in largely rural regions with no local gas distribution infrastructure, using a variety of fuels to meet energy needs (including trucked CNG)[110] that could serve as anchor tenants for expanding gas service.

Primary metals

This sector consists of a group of very energy-intensive industries engaged in the smelting and refining of ferrous (iron-based) and nonferrous (aluminum, copper, lead, etc.) metals, with steel and aluminum production accounting for approximately 80% of natural gas consumption in this segment (60% and 20%, respectively). Steel and aluminum manufacturing have weathered a variety of challenges in recent decades – environmental regulations, other rising costs, technology, and uncertain end-use demand.

Steel

Stagnating levels of domestic production and the steel industry's shift away from gas-intensive technologies have led to declining gas consumption in the US steel sector. There are two main methods used in the production of steel. Steelmakers using an integrated production process (blast furnace method) consume large amounts of natural gas, including some as feedstock to add carbon to steel; whereas those using an electric arc furnace (EF), also known as mini-mills, consume large amounts of electricity to melt steel scrap for reprocessing. Most steel mills constructed in the United States between 1980 and 2000 use electric arc furnace technology, which requires approximately 60% less natural gas. The cost advantage for electric furnaces was clear – if scrap and electricity were less expensive than ore and coal, then the technology was viable, even at lower rates of production than integrated mills, and even with the lower quality of the output. In recent years, however, input costs for EF mills have escalated more than those for blast furnace mills, such that the cost advantage has severely narrowed or disappeared (i.e., the era of cheap scrap is over). Searching for ways to improve the bottom line, EF producers have focused on innovation. Direct-Reduced Iron (DRI), a briquette-forming process relying on natural gas and iron pellets (see the box "DRI and natural gas"), had typically replaced about 15% of the "raw" inputs for EF makers, but producers like Nucor have been able to push that to 50%, filling the rest with scrap steel. In an era of low natural gas prices, DRI presents a good value proposition for non-blast-furnace steel producers.

[110] http://bangordailynews.com/2013/05/16/business/irving-delivers-first-truckload-of-compressed-natural-gas-to-mccain-foods/, accessed 12 August 2013.

DRI and natural gas

Direct reduced iron (DRI, also known as sponge iron) is a product made by processing iron ore into purer, metallic iron without actually melting the ore. Direct-reduction iron-making began in the 1960s and was adopted chiefly by countries lacking a cheap supply of metallurgical coal to make coke. In this process, natural gas or non-coking coal is utilized to generate hot reducing gas, which is a mixture of hydrogen and carbon monoxide, to remove the impurities and the oxide from the iron ore. While there are several ways to make direct-reduced iron products (differentiated by the furnace type, the reducing agent and the input), the method that uses a moving-bed-stack furnace, natural gas, and iron ore pellets has become the most common.[111]

DRI is a semi-finished product and since it could easily re-oxidize if left unattended, generating heat and potentially even catching fire, it is often further processed into hot briquette iron (HBI) for easier transportation and final processing in electric arc furnaces.[112]

World DRI production peaked at 70.4 million tons in 2010 with India, Iran and Saudi Arabia accounting for nearly 70% of the total.[113] The only operating US DRI installation is Steel Dynamics Inc.'s Iron Dynamics plant in Butler, Indiana, which was built in 1998 and uses coal as the reducing agent. The DRI is either compacted into HBI, or is processed further to produce liquid pig iron. In 2012, Iron Dynamics produced 226,000 metric tons of DRI, a very small volume compared to total US blast furnace steel production estimated at over 32 million tons in 2012.[114]

In March 2011, Nucor Corporation started the construction of a $750 million DRI facility in Convent, Louisiana, which is on track for a mid-2013 startup. The 2.5 million ton-per-year facility will use direct reduction technology to convert natural gas and iron ore pellets into high quality DRI used by Nucor steel mills. Subsequent expansions of the complex are likely. In November 2012, Nucor entered into a long-term agreement with Encana for an onshore gas drilling program, which will be used to source fuel for the DRI complex, as well as other Nucor operations.

In addition to the potential savings from the spread between natural gas and metallurgical coal prices, DRI's significance also lies in its carbon dioxide intensity. According to estimates, some DRI plants emit only 1/3 of the CO_2 per ton of steel output as blast furnace complexes.[115]

Future growth of DRI in the United States is almost certain, especially as the cost advantage of natural gas is poised to remain for the long term. The problem is that existing US integrated steel complexes relying on blast furnaces are huge, sunk investments, which have already incurred high costs for retrofitting and upgrading. Walking away from these assets will not be easy for the biggest steel producers, especially as their output possesses superior quality. Therefore, DRI's US expansion is likely to be slow initially, with more capacity coming on line after the cost and environmental benefits outweigh other concerns, likely beyond 2020.

[111] http://www.steelemart.com/steelmak6.asp, retrieved on March 2, 2013.

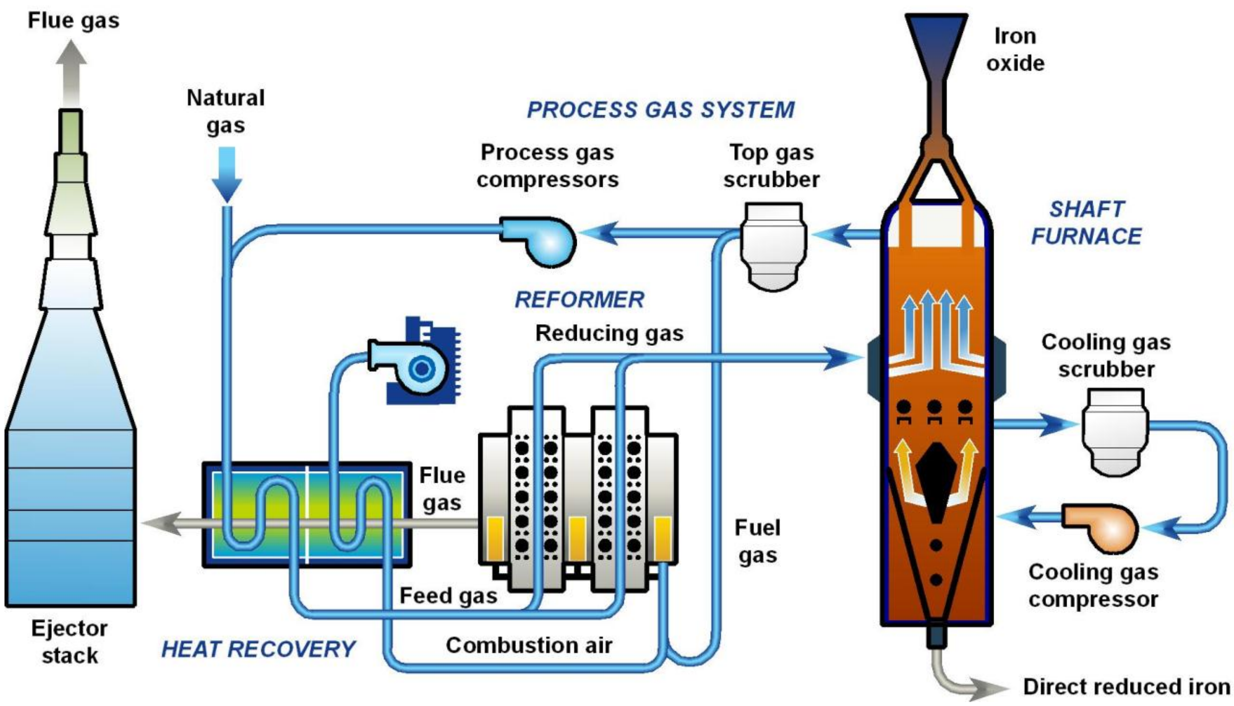
[112] http://www.kobelco.co.jp/english/ktr/pdf/ktr_29/047-049.pdf.

[113] World Steel Association.

[114] Steel Dynamics, 2012 10k.

[115] http://ietd.iipnetwork.org/content/direct-reduced-iron.

Direct Reduced Iron Production Process



Source: IHS CERA based on http://www.kobelco.co.jp/p108/dri/e/dri04.htm, retrieved March 2, 2013

Natural gas consumption in gas-fueled DRI installations is estimated to be less than 10 Mcf per metric ton of DRI. A facility with 1 million metric tons of annual production will require 30 MMcf per day of natural gas.

Similar to many other industries whose end-use demand is tied to the construction and automotive sectors, steel suffered significantly from the 2008-2009 recession. In addition, capacity overbuilding in China towards the late 2000s depressed global steel prices, and supply cuts followed. A bright spot on the demand side during this pullback has been the oil and gas industry, with its growing exploration and development activities and offshore plays requiring high numbers of plates, coils, beams and tubulars. Housing, automotive production, and some purchasing managers' indices (PMI) have trended upwards in 2013, but the outlook for infrastructure construction (highways, bridges, etc.) is tracking sideways at best. Housing starts are showing a good upward trend and by 2014 IHS Global Insight projects that they will have regained their pre-recession level after steadily improving through 2013. However, the same is not seen in infrastructure building. Infrastructure spending fell in 2010 and 2011 by 5.4% and 10.0%, respectively.

The best case scenario for natural gas consumption in the steel industry would probably develop after 2020 as nonresidential construction and automotive production reach and surpass pre-recession levels. The biggest opportunity for natural gas is in the fast expansion of DRI among US steel manufacturers, as this is a very gas-intensive process. Investment in DRI technology could be spurred by a variety of factors – heightened environmental restrictions on blast furnace producers, wider demand for lower-quality steel products and continuing cost advantage of natural gas and iron pellets. Gas can also displace some of the metallurgical coal that is used to make coke for blast furnaces – in fact, U.S. Steel has already reported significant savings in energy costs due to such substitution.

Aluminum

The US aluminum industry has two methods of production. Primary production, which produces aluminum from raw materials or ingots, is now less important than secondary production, which recycles aluminum scrap into new products. In the primary production process, natural gas is used chiefly in converting bauxite into alumina (aluminum oxide), which is later treated by electrolysis (typically consuming high quantities of electricity) into aluminum. Secondary production is much less energy-intensive.

Aside from end-use markets (construction, automobiles, aerospace and beverages) resuming strong growth patterns, the upside for natural gas in this segment lies in increased primary production of aluminum. An additional boost could come from smelters changing on site electricity generation to gas-fired turbines and more facilities reducing purchases of grid electricity or focusing on distributed generation where natural gas is the main fuel option. These options could likely be realized mostly after 2015 as aluminum producers still need to be convinced about the availability of cheap gas to make the necessary investment decisions.

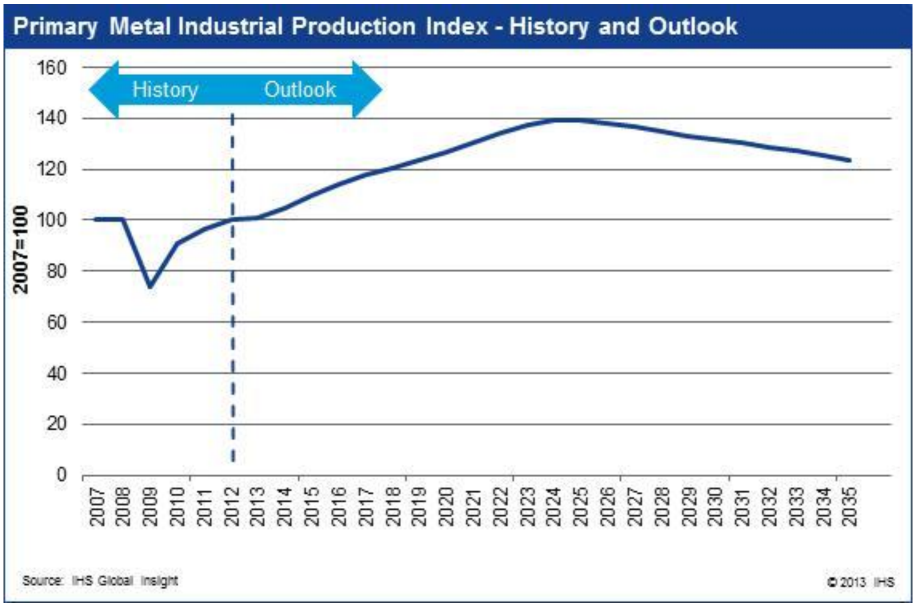
The primary metals industry is heavily concentrated in the East North Central and Mid-Atlantic regions, which contain over 50% of all primary metals plants in the United States.[116] The industrial natural gas throughput served by gas LDCs in these states is very high (Illinois has the lowest percentage at 72% based on 2010 data), so utilities should be well-positioned to meet any incremental demand coming from existing facilities.

IHS Global Insight projects a 2.6% compound annual growth rate for primary metals production through 2025 (see Figure VII.7). Thereafter, the benefits of low-cost energy inputs in the United States are expected to lose ground to countries with ample supply of raw materials and ore like Chile, Brazil and Australia.

IHS CERA estimates that natural gas consumption by this industry will grow to about 1.7 Bcf per day by 2025, but then will gradually decline to about 1.4 Bcf per day by 2035 due to efficiency gains and unfavorable competitive position.

[116] IHS Inc., Major Industrial Plant Database.

FIGURE VII.7



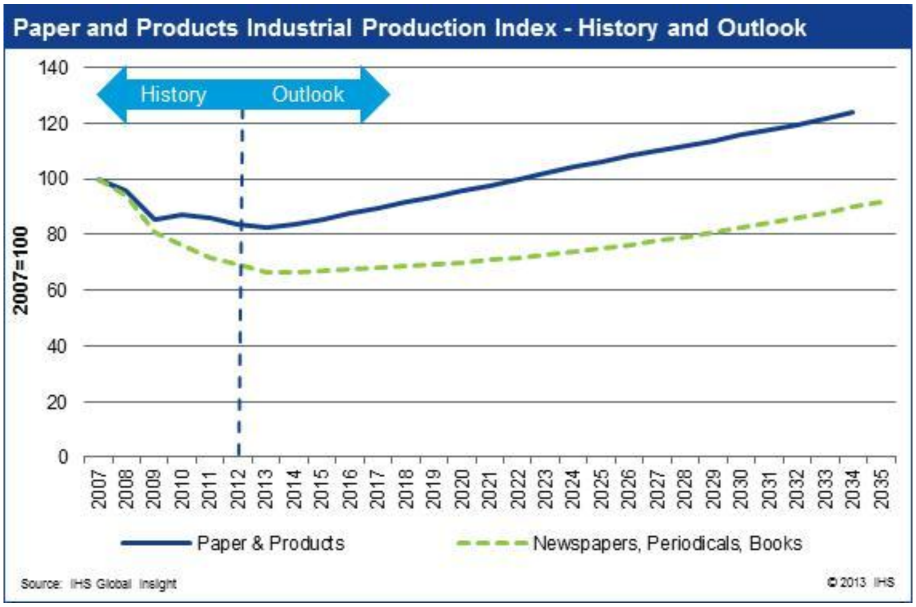
Pulp and paper products

The pulp and paper industry is segmented into two main components. Pulp and paper mills process wood fiber to make pulp and/or paper. Paperboard mills use wood pulp and other fiber pulp to manufacture more specialized products. This is the fifth largest industry in terms of industrial gas consumption in manufacturing, with about an 8% share. Paper and paperboard mills have achieved tremendous gains in energy efficiency as well as in using biomass (wood wastes and chips) to meet some of their electricity needs in recent years. Both trends have affected gas consumption negatively. The larger issue, however, has been the continuously declining use of paper and its related products in the US economy, chiefly the printing and publishing industries, as preferences have shifted firmly to electronic media. While the recession in 2008-09 hit paper demand hard, the post-recession period saw further declines. Demand for paper products fell more than 5% and 4% in 2011 and 2012, respectively, and this trend is expected to continue. Commercial printing, a key driver industry, saw a 2% output decline in 2012, and is likely to decline more than 4% in 2013 and nearly 2% in 2014. Magazine ad pages are expected to see a 7% drop in 2013 and a 4% decline in 2014. The response has been idling or shutting down of higher-cost capacity.

The bright spot in this segment is paper-based packaging. It is currently going through a setback, but its long-term potential remains positive, especially as recycling, while having made gains in recent years, is still a long way from making a dent in primary production of paper-based packaging. The recovery in US manufacturing largely stalled in 2012 and most of the markets tied to paper packaging (processed foods, beverages, tobacco manufacturing and pharmaceuticals) are expected to see very little, if any, growth in 2013. Not until manufacturing begins to reaccelerate in 2014 will packaging see steady increases in demand in 2015 and beyond, averaging 2–3% annually. Overall, the industry is poised to recover rather slowly to pre-recession levels by 2023 and continue on a slow growth path thereafter (see Figure VII.8).

Pulp and paper facilities, however, are among the few remaining industrial establishments where sizeable fossil fuel substitution is possible, especially in the Northeast. According to the IHS Major Industrial Plant Database (MIPD), 75 of 824 pulp- and paper-related plants do not have a natural gas connection, burning instead fuel oil or propane, in amounts that equate to about 0.1 Bcf per day of natural gas at full operating capacity. Conversion of these facilities, most of them in sparsely-populated areas, to natural gas could provide opportunities to expand gas infrastructure to neighboring population centers and serve as anchor tenants.

FIGURE VII.8



Nonmetallic minerals (stone, clay, cement)

The nonmetallic minerals industry transforms minerals such as stone, clay, and refractory materials into manufactured products such as cement, bricks, and glass. Most of the natural gas consumed in this industry is used in industrial processes that require process heating, such as glass melting and clay firing. Nonmetallic minerals manufacturers used about 0.7 Bcf per day of natural gas in 2010, of which nearly 50% went into glass production.[117]

Glass

The two main segments of the glass industry – flat glass and container glass – have been consistently challenged by lower-cost foreign competition, and imports are now a substantial share of total US glass supply. On the demand side, the 2008-09 recession negatively affected the main end-use sectors for glass – construction, automobiles and consumer products – and as a result, some glass plants were shut down, with plenty of underutilized capacity remaining.

The recent wave of positive data from the construction and automotive industries indicates that flat glass demand will be inching back up. Growth in 2013 is projected at about 3%. Any real pickup in demand is not expected until 2014, but even then total output is expected to remain below pre-recession levels until 2017. Thereafter, a strong growth in the construction industry (both in new builds and refurbishments)

[117] US Energy Information Administration, *Manufacturing Energy Consumption Survey*, 2010.

could buoy flat glass production. An intriguing and potentially high-growth niche market for flat glass (albeit with a serious low-cost competition from abroad) is solar panels/cells, which could expand tremendously over the long-term driven by needs of renewable power producers.

The other major glass type, container glass, underwent a long period in which producers focused on “light-weighting”--reducing the thickness of a glass product, such as a bottle or container--so that it consumes less glass and hence less raw materials such as energy (natural gas). Glass was also phased out of some end uses, for example some beverages, in favor of plastics such as PET packaging resin. Recently, container glass has returned in some packaging uses in preference to plastics (a) because of consumer perceptions that products in glass containers are high value, (b) because glass is considered more environmentally friendly as it can be recycled more easily, and (c) because glass is considered to be a safer option for products such as baby foods. The potential gains for natural gas consumption, however, would be limited, unless the switch away from plastic packaging is widespread.

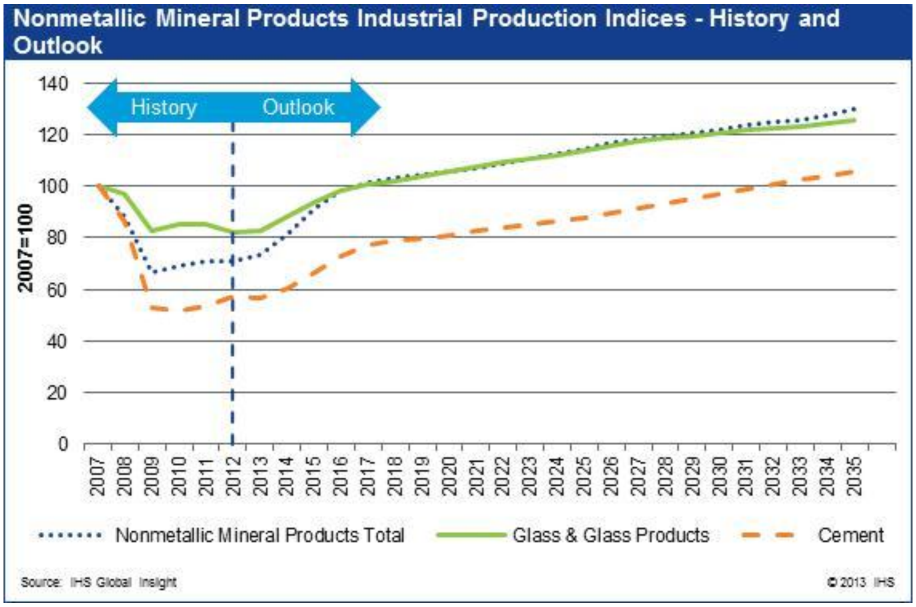
IHS Global Insight projects that value-added glass output will increase by 1.9% per year through 2035 but efficiency improvements and other process restructuring will keep gas consumption in the industry essentially flat in the long-term.

Cement

Nowhere has the recession been more evident than in cement production (see Figure VII.9). The downturn in construction spending since 2007 hit the cement industry so hard that the industry dramatically trimmed both foreign imports and domestic production. By 2009, twelve plants had been closed and only three new ones came on-stream. In 2012, for instance, about 71 million tons of Portland cement and 2 million tons of masonry cement were produced, but this is much lower than the levels in 2002–07, which exceeded 90 million tons per year.[118] US cement demand has since come off its lows due to the revitalization of construction and it is expected to begin to accelerate in early 2014. Given that cement is heavily dependent on nonresidential construction, which has been slow to show improvement, the ultimate recovery is likely years away. IHS Global Insight does not expect cement to recover its 2007 level of output until 2032. A significant and unanticipated pickup in public and private infrastructure spending could have a positive impact on cement production and on natural gas demand in this industry.

[118] http://minerals.usgs.gov/minerals/pubs/commodity/cement/.

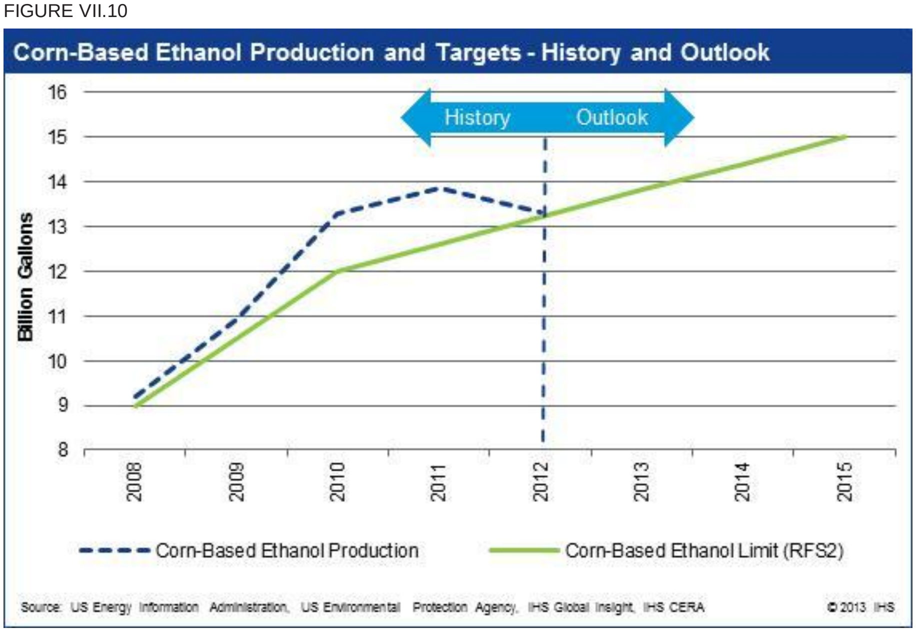
FIGURE VII.9



Ethanol

Fuel ethanol production has expanded rapidly since the early 2000s under the Renewable Fuel Standard (RFS), modified in 2007 by the Energy Independence and Security Act to the RFS2. The RFS2 requires an amount of biofuels to be blended into gasoline each year, of which a certain proportion can be met by corn ethanol (reaching a ceiling of 15 billion gallons in 2015). The rest of the biofuels target is to come from “advanced biofuels” (such as cellulosic ethanol) reaching at least 21 billion gallons by 2022. Corn-based ethanol producers, aided by the federal mandate, low barriers to entry, economies of scale, and abundant corn supplies, quickly ramped up capacity and production in response, reaching a record 13.9 billion gallons of ethanol output in 2011, surpassing the RFS2 blended target for that year of 13.2 billion gallons by nearly 6% (see Figure VII.10).

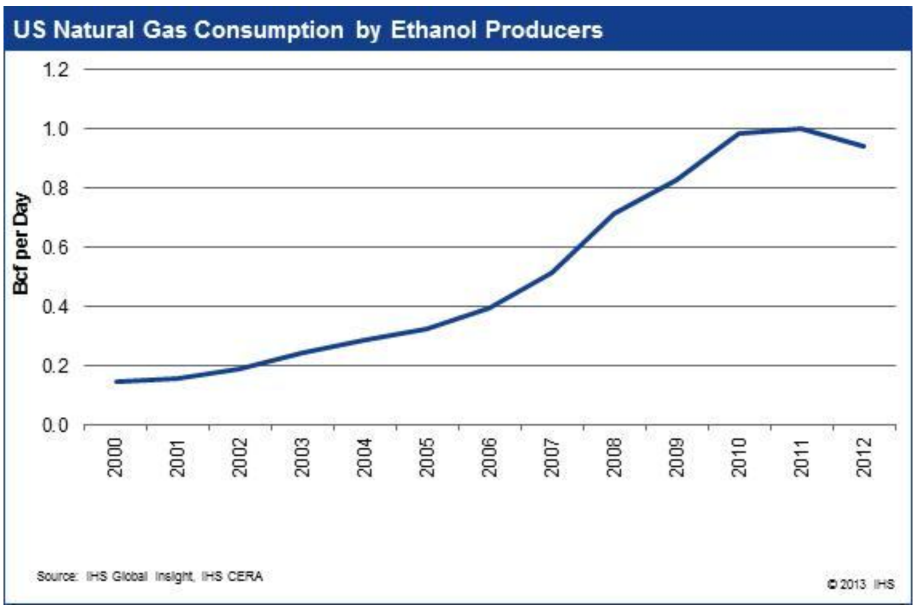
FIGURE VII.10



Natural gas is a key energy component in the production of corn-based ethanol, and usage has grown concurrently with ethanol output (see the box "Natural gas consumption in corn-based ethanol production"). From less than 0.2 Bcf per day in 2000, it averaged nearly 1 Bcf per day in 2011, according to IHS CERA estimates, before dropping to a little over 0.9 Bcf per day in 2012 due to unfavorable fundamental conditions including tight corn supplies, flat gasoline demand and accumulation of renewable trading certificates due to overproduction in previous years (see Figure VII.11).

US ethanol demand relies primarily on mandates enacted under the RFS2. Because corn-derived ethanol blending occurs chiefly through the E10 gasoline mix (10% ethanol/90% gasoline), US gasoline consumption is a significant demand-side driver for ethanol. But relying on E10 creates two obstacles to expanding ethanol use. First, US gasoline consumption has been declining since 2005 as more fuel-efficient vehicles continue to join the light-duty fleet, and the growth in vehicle miles traveled has also slowed. As a result, demand for ethanol to produce E10 has declined. Second, the E10 standard limits total domestic demand for ethanol to 10% of US gasoline consumption.

FIGURE VII.11



The RFS2 stipulates progressively increasing volumes of conventional ethanol to be blended in gasoline in the next three years (13.8 billion gallons in 2013, 14.4 billion in 2014, and 15 billion in 2015). However, with the E10 blend wall having been reached and gasoline demand projected to continue declining, it is a foregone conclusion that the E10 blend by itself will not meet the rising RFS2 mandate. With gasoline consumption at 133–134 billion gallons per year, the E10 blend wall will limit blending ethanol demand to slightly more than 13 billion gallons per year. Breaching the E10 blend wall is possible through greater use of flexible-fuel vehicles (FFVs) or widespread adoption of the E15 blend (15% ethanol/85% gasoline). FFVs designed to run on gasoline or on blends of up to 85% ethanol (E85) have been in production since the 1980s. However, they have not become a significant part of the US light- and heavy-duty fleet because of ethanol's inability to maintain price competitiveness with gasoline and a lack of fueling stations and infrastructure beyond the midwestern states. EPA has approved E15 for use in vehicle model year 2001 and newer. However, concerns about engine performance, misfueling liabilities and vapor pressure, and an inadequate number of fueling pumps have essentially stopped progress.

Natural gas consumption in corn-based ethanol production

A typical dry-milling corn ethanol plant needs natural gas to fuel a steam boiler to treat the corn starch and generate the necessary heat to distill the alcohol and dry the dried distillers grains with solubles (DDGS). Gas is also used to flare volatile organic compounds and to remove moisture from the final product.

Since energy inputs are the second largest variable cost after the corn, ethanol producers have consistently tried to reduce natural gas' impact on their bottom line by improving the efficiency of the distillation process and incorporating combined heat and power technologies to reduce grid-purchased natural gas. Retrofits of existing production equipment have also been widespread. Energy can also be saved in the process by not drying the DDGS by-product but disposing of it in a wet form. However, this option both adds to the product's shipping weight and hastens spoilage, so it is not the typical choice.

IHS CERA estimates that the natural gas consumption rate per gallon of ethanol output among the largest producers using the dry milling method averaged about 26,000–27,000 Btu in 2012. This is a significant reduction from the early 2000s, when ethanol producers needed 34,000–35,000 Btu of natural gas per gallon of ethanol as dry mills were still not widespread.

In addition to the energy-saving methods described above, producers have experimented with various innovative enzymes that improve the recovery of by-products, reduce energy needs, and boost nameplate plant capacity as the nonfermentable material is removed earlier in the process. IHS CERA assumes that further efforts to lower the energy intensity of the dry-milling process could yield an average 1.5% decrease in natural gas needs per gallon of output per year.

Even if E15/E85 fuels achieve a greater penetration in the US market (and that will come at the expense of E10), corn-derived ethanol blending is limited to 15 billion gallons per year until 2022. Expanding output levels of corn-derived ethanol to that maximum would not be a problem with existing biorefinery capacity, but it would add very little natural gas demand over the levels already achieved due to continued energy efficiency gains. Therefore, any meaningful upward potential for gas consumption in ethanol production would come from lifting the 15 billion gallon cap in the RFS2, concurrently with ensuring widespread acceptance of E15/E85. Additional factors that could help prop up US corn-derived ethanol output (and related natural gas demand) include renewed growth of gasoline demand, failure to develop domestic commercial-scale quantities of cellulosic ethanol and other advanced biofuels, continued strong exports to Canada and Europe and reduced supply from major global ethanol market players such as Brazil.

Note also that the increased natural gas consumption derived from the ethanol mandate is to some extent offset by reduced natural gas used in petroleum refineries, whose output is reduced by the ethanol requirement. Finally, to the extent that natural gas (and other alternative fuel) vehicles gain market share from gasoline vehicles, ethanol production and natural gas consumption by the ethanol industry will be reduced.

Corn-based ethanol biorefineries are clustered in the corn-producing states in the Midwest – Iowa, Nebraska, Illinois, Indiana and Minnesota. Since most facilities are in rural areas, far from gas LDC networks, they get natural gas directly from nearby pipelines. In recent years many ethanol plants have also improved their abilities to use cheap waste products and other alternative energy sources to meet boiler needs.

Gas-to-liquids (GTL)

The expectation that low natural gas prices will persist for many years has re-ignited discussion of ways to benefit from the spread with high and volatile oil prices. Converting natural gas into synthetic fuels, e.g., GTL using the Fischer-Tropsch process, is a known technology (see the box "GTL technology – Fischer-Tropsch process") that has already been used in commercial plants for many decades. Sasol operates the Mossel Bay in South Africa and Shell has two plants—Bintulu in Malaysia and Pearl in Qatar. Pearl achieved full capacity only in 2012. GTL plants across the globe have consistently had very challenging economics due to a multitude of factors affecting the bottom line – chiefly the very high capital costs of launching the projects, but also high operating and feedstock costs and low value of the finished products.[119]

Nonetheless, interested parties in the United States have shown a willingness to look into both small- and large-scale GTL plants. In 2012 Calumet Specialty Products, a chemicals manufacturer, announced a 1,000 bd GTL addition to its chemical plant in Karns City, PA, with the goal of reducing costs, increasing security of supply and improvement of product quality. Much more attention was given to Sasol's December 2012 decision to proceed with the front-end engineering and design (FEED) phase of an integrated GTL and ethane cracker complex in Lake Charles, LA. Total investment is expected to be between $16 and $21 billion, with a startup date in 2018. Buried in the fine print of the announcement was the projected ability of the plant to swing between fuels and high-value chemicals as output based on market conditions, which underscores the uncertainty associated with operation.

Whether many new GTL facilities will begin showing up across the United States depends chiefly on continuing a favorable oil-to-gas price spread, capability to line up sufficient financial resources and ability to wait out the long construction periods. Any significant impact on natural gas demand will be beyond the 2020 time frame.

GTL technology—Fischer-Tropsch process

A GTL plant consists of two major components and a number of supporting units. The first major component is a reformer to convert the natural gas into syngas. Syngas generation is performed in an autothermal reactor using a conventional nickel-containing reforming catalyst supported on alumina-silica. The second major component is the Fischer-Tropsch synthesis reactor. This unit converts the syngas into long-chain hydrocarbons by passing it over an iron or cobalt catalyst. The reactor operates at a high temperature of 229°C (444°F) and a high pressure of 19.7 kg/cm^2 (280 psia). The vapor and liquid reactor effluents undergo primary and secondary fractionation to separate the heavy waxy hydrocarbons from the diesel and lighter fractions. The waxy hydrocarbon fraction undergoes hydrocracking to yield additional product.

[119] See the IHS Inc. Private Report *Gas-to-Liquids: A Reserve Ready to be Tapped.*

IHS Chemical estimates that about 36,900 Btu of natural gas feedstock (excluding any gas for electricity generation) is required to produce one pound of synthetic diesel or nearly 108 MMcf per 10,000 barrels. If Sasol's projected Lake Charles GTL facility conforms to these specifications and operates at 100% of its target rate of 96,000 bd, this will require nearly 1.04 Bcf per day of natural gas feedstock. It is unlikely, however, that any large-scale GTL facility will turn to gas LDCs for its feedstock needs; such plants will require large-volume interstate pipeline connections.

Gas-fueled drilling rigs

Another opportunity to decrease fuel expenses based on the price differential between diesel and natural gas lies in converting drilling rigs in conventional and unconventional oil and gas plays to run on LNG or CNG. Operators are also interested in natural gas-fueled rigs because they could possibly reduce local drilling emissions. As much as 4 billion gallons of diesel per year are consumed by drilling rigs, which translates to about 1.4 Bcf per day of natural gas demand if full conversion were achieved. Several companies have done pilot projects using truck-mounted (small-scale) liquefaction units to supply the LNG or rigs directly to field gas (from wellheads), but these efforts are still in the early stages. Technological improvements to increase the thermal efficiency of LNG engines, the reliability of the power delivery and buildout of the necessary refueling infrastructure will be needed before natural gas-fueled rigs achieve a substantial share of this market. Most of the initial modifications will likely be to allow rigs to operate in a dual-fuel mode (natural gas and/or diesel) to ensure a fallback option in case of performance issues while running on natural gas.

Opportunities for fuel-switching and increased efficiency

Residual and distillate fuel oils, coal, and coke together accounted for less than 11% of all fuel and feedstock energy uses in the US manufacturing sector in 2010.[120] There is potential in certain processes to displace these competing energy sources further—for instance by substituting natural gas for some of the coke used in blast furnaces or by using more direct-reduced iron instead of scrap steel in electric arc steelmaking as mentioned earlier in this chapter. But little incremental gas demand is anticipated to be gained. One serious factor limiting increased natural gas switching is the lack of availability of the gas distribution network for manufacturing facilities in remote locations. Also, the high natural gas prices of the past decade—in conjunction with concerns about the environment—unleashed a series of conservation and energy efficiency efforts in every energy-intensive industry intended to reduce fossil fuel consumption. Large-scale recycling—for instance, in aluminum, paper, scrap steel, and plastics—minimizes the need for new production and consequently curbs energy usage. During the 2008-09 economic recession, many manufacturers avoided making major investments to replace aging capital equipment, and in the next few years more energy-efficient and advanced machinery and tools will roll out on production floors. Gas LDCs are well-positioned to assist in these efficiency and conservation efforts. Gas LDCs offer prescriptive and custom programs and some incorporate strategic energy management programs into their portfolios. One challenge to gas LDCs in supporting industrial energy

[120] US Energy Information Administration Manufacturing Energy Consumption Survey 2010, Table 1.2.

efficiency is the regulatory allowance for industrial customers to opt-out of utility offered programs, making it more difficult to advance energy efficiency in this sector. Nevertheless they can engage in efforts to increase efficiency for manufacturing customers, can improve and diversify customer program offerings, help customers utilize efficiency as a least-cost resource, and help meet state or corporate energy savings requirements.

Using natural gas to reduce boiler emissions

In December 2012, EPA issued a final rule establishing air toxics standards for industrial and commercial boilers and certain waste incinerators. EPA says the rule targets about 2,300 oil- and coal-fired boilers at large industrial and commercial facilities requiring compliance with new emissions standards by 2016. Because of the lower emissions from natural gas, boilers fueled with natural gas are not subject to the same numeric emissions limits but rather must comply with a set of work practice standards to reduce emissions. As a result natural gas applications are one of the compliance options for affected facilities. Many boiler operators may find it is more cost-effective to switch to natural gas rather than install pollution controls on older oil or coal-fired units. One possibility is the use of combined heat and power units in facilities with large thermal loads. The added efficiency and ability to generate electricity on site could provide a payback to compensate for the higher up front investment cost of the combined heat and power system.

LDC opportunities in the industrial sector

The outlook for industrial natural gas use is mixed. There are solid expectations of capacity growth in the chemical sector, with as much as 3 Bcf per day of additional gas demand that could materialize by 2035. Much, but not all, of this incremental demand is likely to bypass the gas LDC system however, as growth is expected to occur primarily in Louisiana and Texas, where most industrial gas consumption occurs outside the city gate.

Of the other major gas-consuming industries, food processing, primary metals and various metal-based products (fabricated products, transportation equipment, machinery, electrical equipment) have the best prospects for increasing natural gas use, potentially adding about 1 Bcf per day to gas demand by 2035. A moderate gas consumption rebound will also occur in nonmetallic minerals once cement production recovers from the deep bottom it hit during the recession. Another 1 Bcf per day could come from a single GTL plant.

Gas use in other industries is likely to remain flat at best. Gas use in petroleum refineries is expected to decline as refinery output falls and as light, sweet crude oil increases its share of refinery input, although increased exports of refined products can counter that decline. Gas use in ethanol production has fallen as ethanol production has hit the E10 blend wall, the E15 blend has not broken through in the market and the RFS2 has remained unchanged. Gas demand from the paper industry faces an uphill battle, as most of the sector faces very challenging times ahead.

Notwithstanding the expected surge in chemical gas demand, overall industrial natural gas demand growth is likely to be slight, as gains in some industries are offset by losses in other industries. Many of these industries are affected by global economic conditions and increasing competition and may not expand significantly, which will affect their gas consumption. Nonetheless, potential growth in total US industrial gas load could surpass 5 Bcf per day by 2035 over 2010 levels (see Table VII.9).

About 53% of industrial gas use now goes through gas LDC systems, with the proportions varying from a low of 2% in Louisiana to 100% in many New England states as well as North Carolina. Assuming that these patterns of gas LDC industrial deliveries remain stable, IHS's regional projections of industrial gas demand suggest that gas LDCs' industrial load could increase by 2 Bcf per day by 2035, with the chemical industry accounting for more than one-quarter of this increase (see Table VII.10).

TABLE VII.9

Potential Growth in Industrial Natural Gas Consumption
Bcf per day

	2012	2015	2020	2035
Chemicals	0.11	0.60	1.95	2.98
Petroleum Refining	0.16	0.18	0.22	0.09
Food	0.07	0.14	0.27	0.68
Primary Metals	0.03	0.06	0.14	(0.07)
Pulp & Paper	(0.04)	(0.01)	0.08	0.36
Nonmetallic Minerals	0.02	0.17	0.27	0.42
Metal Durables/Machinery/Transp. Equipment	0.20	0.36	0.50	0.60
Total	**0.55**	**1.50**	**3.44**	**5.06**

Source: IHS CERA

TABLE VII.10

Potential Growth in LDC Deliveries to Industrial Customers
Bcf per day

	2012	2015	2020	2035
Chemicals	0.03	0.08	0.37	0.58
Petroleum Refining	0.08	0.09	0.12	0.04
Food	0.05	0.10	0.20	0.50
Primary Metals	0.02	0.04	0.10	(0.05)
Pulp & Paper	(0.03)	0.01	0.06	0.29
Nonmetallic Minerals	0.01	0.12	0.20	0.30
Metal Durables/Machinery/Transp. Equipment	0.15	0.27	0.37	0.44
Total	**0.31**	**0.69**	**1.42**	**2.10**

Source: IHS CERA

Implications for gas LDCs

- The fact that nearly half of industrial customers are served by gas LDCs presents a growth opportunity in the industrial sector.
- LDCs need to devise strategies to maintain or increase their share of industrial gas deliveries.
- LDCs can work with local communities to attract gas-intensive industries to serve as anchor tenants and reduce the costs of system expansion.
- Gas LDCs may have opportunities to work with regulators to diversify energy efficiency offerings to industrial customers.

Chapter VIII: Natural Gas for Power Generation

In Brief

- Abundant domestic natural gas production and sustained low gas prices have game-changing implications for power generation, increasing market share for natural gas-fired generators and resetting the cost and environmental benchmarks for new generation capacity additions. Natural gas consumption by the electric power sector is expected to almost double from current levels, increasing by 24 Bcf per day by 2035.
- Gas LDCs could deliver nearly 12 Bcf per day of natural gas throughput to power companies in 2035, if 2011 delivery shares are maintained.
- Natural gas' role in the future generation mix will be affected by the power industry best practice that fuel and technology be diversified inside a power generation portfolio. State mandates mean that gas must compete with renewables to share new nameplate generation capacity.
- In addition, natural gas–fired power plants provide the lowest-cost source of integration for intermittent renewable power generation technologies. Because natural gas-fired generation is a dispatchable resource, it acts as the primary source to firm the intermittent power supply from renewable sources and also to balance continuously changing power loads.
- The growing role of natural gas in power generation will require even closer coordination between natural gas suppliers and power generators, with gas/power system harmonization a major focus of electric system regional transmission operators and the FERC. Gas LDCs could provide valuable services in the harmonization of the two systems including operational balancing of natural gas supplies.

In the last two decades, natural gas has been the only fossil fuel with an increasing market share in US power generation. The proportion of power generated by natural gas has nearly doubled since 1990 while the market shares for both coal and oil declined. The increased availability of natural gas from the Shale Gale reinforces this trend. IHS CERA expects natural gas to capture a significant share of the growth in US power markets over the coming decades. In addition, we expect that natural gas will overtake coal and capture the largest share of the US generation market in the early to middle part of the 2020s.

The growth outlook for natural gas in the power sector is underpinned in part by a shift away from coal-fired generation as discussed in more detail below. However, in most power markets natural gas-fired generation will continue to share the stage with a growing fleet of renewable generators, wind and solar in particular. Public policy continues to drive additions of renewables, with implications for the role and economics of natural gas-fired generation in the power system. In this chapter, IHS CERA analyzes the implications of natural gas in the power sector and the regulatory and economic forces giving natural gas an advantage over other conventional generation options—coal-fired generation in particular. We discuss the role gas-fired generators will play in maintaining power grid reliability and the technology shifts that are widely believed to hold the potential to alter the growth trajectory of gas-fired generation. Finally, we close with a discussion of the opportunity for gas LDCs to capture power sector load going forward.

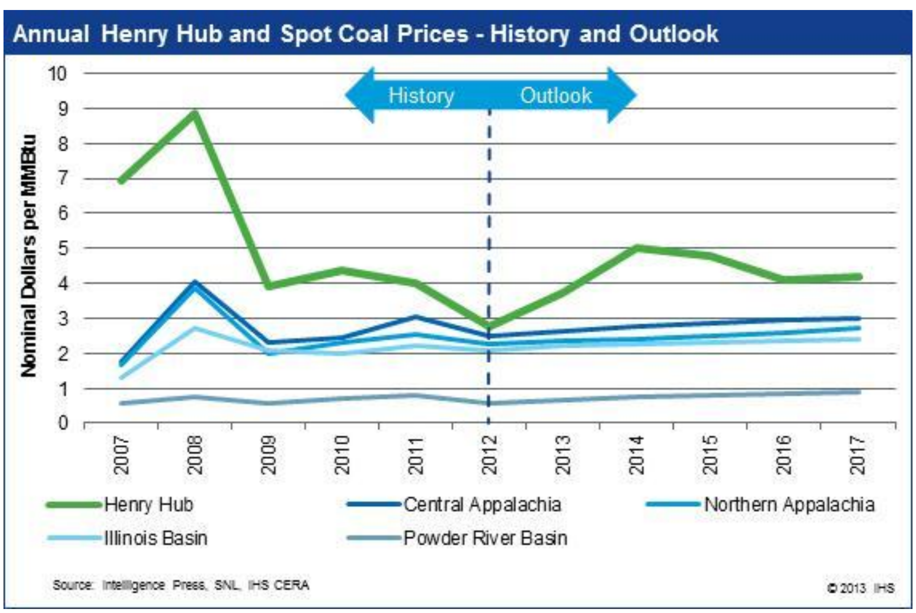
Shifting away from coal-fired power

The advance of gas-fired power generation at the expense of coal-fired power in the United States is the result of three related market factors: displacement of coal-fired generation by natural gas-fired generation in economic dispatch, the expected retirement of about 17% of the existing coal generation fleet during the current decade, and the regulatory and economic forces that hinder development of new conventional coal-fired generation.[121]

Gas displacement of coal in power generation

In the past three years, power sector demand for natural gas has grown as low gas prices have significantly reduced the spread between gas and coal prices, making gas-fired generation increasingly competitive with coal-fired generation for electric dispatch (see Figure VIII.1). IHS CERA estimates that, relative to 2008, 2011 gas demand for power generation increased by 3.8 Bcf per day as a result of coal-to-gas displacement – gas and coal typically compete at the margin in several US power markets when the price spread between the two fuels tightens.[122] We benchmark coal-to-gas displacement against 2008 because high natural gas prices kept coal-to-gas displacement at a minimum for that year. Natural gas prices in 2012 averaged a cyclical low of $2.75 for the year, the result of an abnormally warm winter, overproduction, and excess natural gas storage inventories. This further tightened the spread between coal and natural gas prices, precipitating a more than doubling of coal displacement to an average 8.2 Bcf per day in incremental natural gas demand for 2012 as compared with 2008. IHS CERA estimates that displacement of coal-fired generation also resulted in 2011 and 2012 power sector GHG emissions falling to about 11% and 17% below 2005 levels, respectively (see Chapter III for further discussion).

FIGURE VIII.1



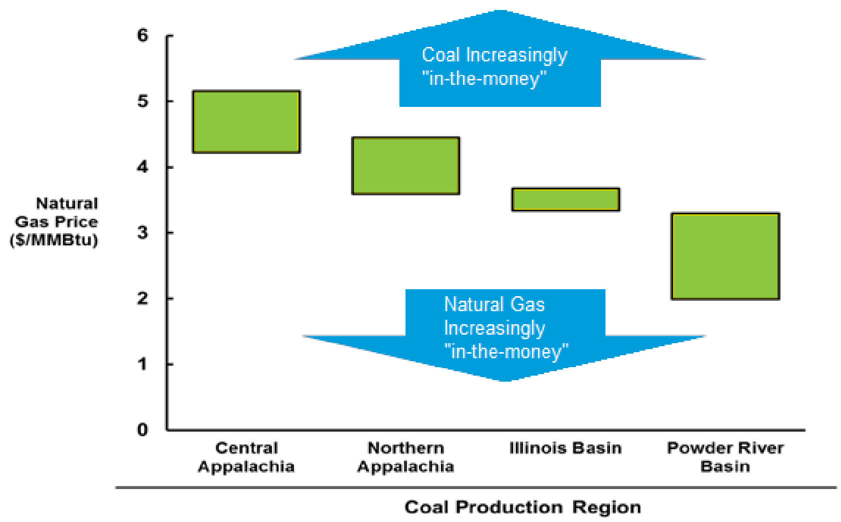
[121] Conventional coal-fired generation refers to facilities built without carbon capture and storage technology.

[122] Dispatch economics are primarily a function of fuel prices, heat rates and other operating costs. Since gas generation plants often have a lower heat rate than coal generation plants, gas prices can be higher than coal prices, yet gas generation will be more economical to dispatch.

IHS CERA expects coal-to-gas displacement to abate gradually during 2013 as rising natural gas prices rebound to more sustainable levels from their glut-induced lows of 2012, improving coal's competitive position. Figure VIII.2 illustrates the competitive position of coal against natural gas by coal supply basin, showing how coal from various regions becomes increasingly competitive against natural gas as gas prices increase. The bars vary based on the energy and quality content of the coal and the production and shipping costs. With 2013 average Henry Hub prices rising to $3.66 per MMBtu for the year, we expect coal displacement to be lower than 2012 levels. This abatement is expected to be sustained in 2014 and 2015 as gas prices undergo an upward pricing cycle before settling in at around their full life cycle breakeven point of $4 per MMBtu (constant 2012 $). In the longer-term, however, power sector gas demand is expected to grow steadily as existing coal-fired generators retire, electricity demand increases, and new gas-fired generation retains its cost advantage over other new competing technologies, including renewable energy generation.

FIGURE VIII.2

Competitive Position of Coal Relative to Natural Gas in US Power Generation



Regulations target coal-fired power

For the existing coal fleet, more stringent EPA restrictions on conventional air emissions (SO_2, NO_x, mercury, and other hazardous air pollutants), coal ash disposal, and cooling water use will force decisions between investment in costly environmental upgrades and retirement for many coal units over the next few years (see Figure VIII.3). Facing difficult and costly emission control retrofit decisions in the wake of cyclical low natural gas prices, many coal plant operators will be looking to shelve or completely retire some coal units. IHS CERA estimates that more than 50 gigawatts (GW) of coal-fired generation capacity will be retired between 2011 and 2020. This accounts for roughly one sixth of the existing coal fleet. These retired plants will generally be the smaller, older, and less efficient units that currently operate at reduced capacity factors. IHS CERA estimates that, assuming natural gas generation is used to replace the power previously generated by these retiring coal-fired units, incremental gas demand will average about 3.5 Bcf per day (see Figure VIII.4).

FIGURE VIII.3

Timeline for Key EPA Regulations Impacting the US Coal Generation Fleet

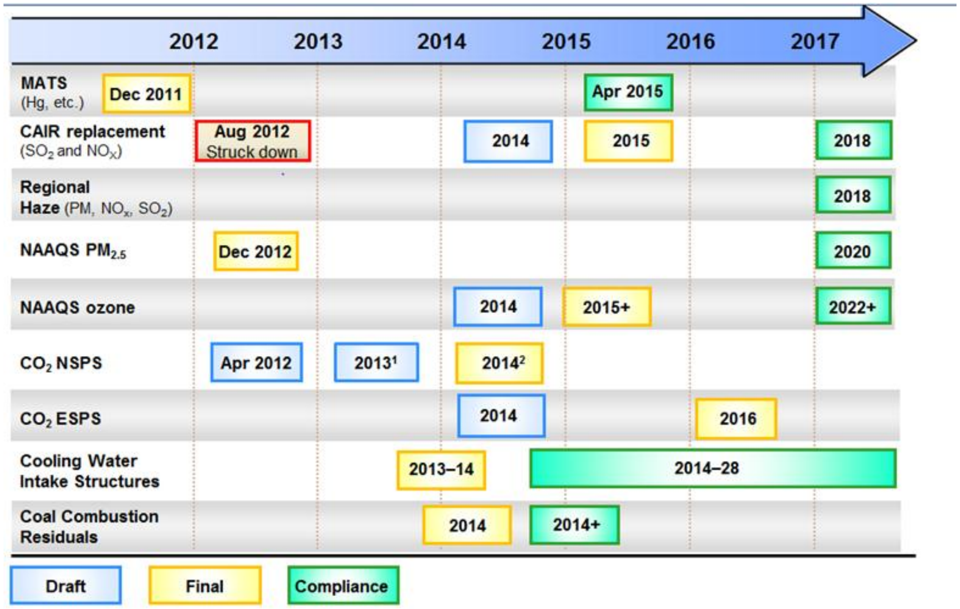
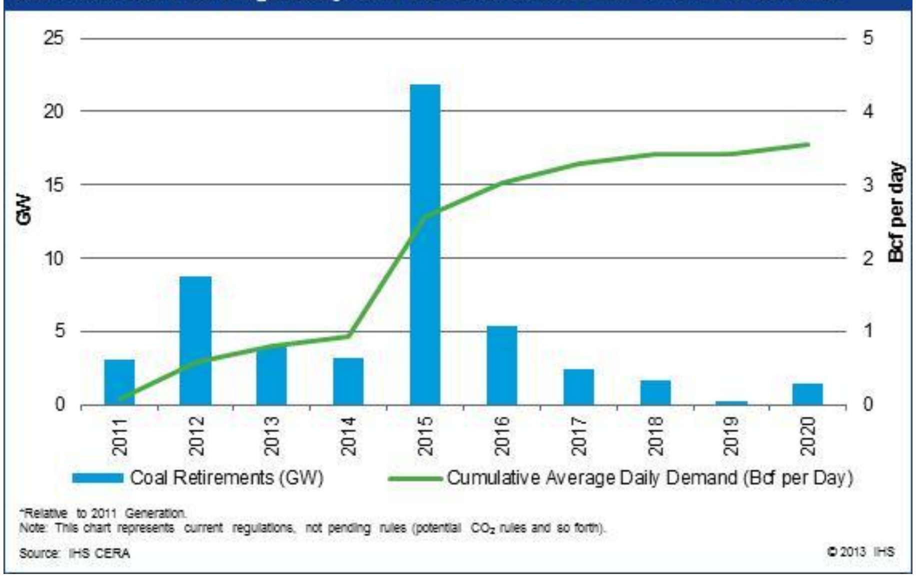


FIGURE VIII.4

US Cumulative Average Daily Gas Demand Gains from Coal Retirements*



In addition, EPA's proposed regulation targeting CO_2 emissions from new fossil fuel–fired power plants includes an emission performance standard that effectively blocks the construction of new coal units inside the United States, at least until carbon capture & storage (CCS) has a better chance of becoming deployed, which is unlikely before 2030.

Technical and cost advantages of natural gas-fired generation

The power system is built, out of necessity, with reserve capacity and with a range of technologies designed to play different but equally important roles in reliably meeting consumer demand for electricity. Base-load power units—designed to provide the bulk of power to customers across all twenty-four hours of the day—run at high utilization rates and, therefore, are able to spread their capital costs over more units of electricity. Cycling, or intermediate, power units change their utilization rates up and down routinely in response to variations in load. Peaking power units start up quickly to meet the highest, but infrequent, levels of power demand. An hour-by-hour combination of these generating technologies cost-effectively matches power supply to the expected variations in power demand through time. Natural gas-fired power generation technologies can provide capacity to meet the technical requirements of all three power plant roles.

All three main power generation technologies can be fueled with natural gas:

- Combined-cycle gas turbines (CCGTs) burn gas in combustion turbines and then use their hot exhaust gases to generate steam 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.[123] They can also serve peaking and cycling roles. Natural gas-fired CCGT is typically the lowest-cost option for customer load levels occurring more than 40% of the time (base-load and intermediate generation).

- Combustion turbines (CTs) are also deployed in "simple cycle", or stand-alone, basis without a steam cycle. CTs provide rapid start-up and quickly reach their peak output, but at much lower overall efficiency as compared to CCGTs. CTs are less capital intensive than CCGTs and typically are the lowest-cost power supply option for customer demand levels that occur 40% of the time or less (e.g., intermediate and peaking generation roles).

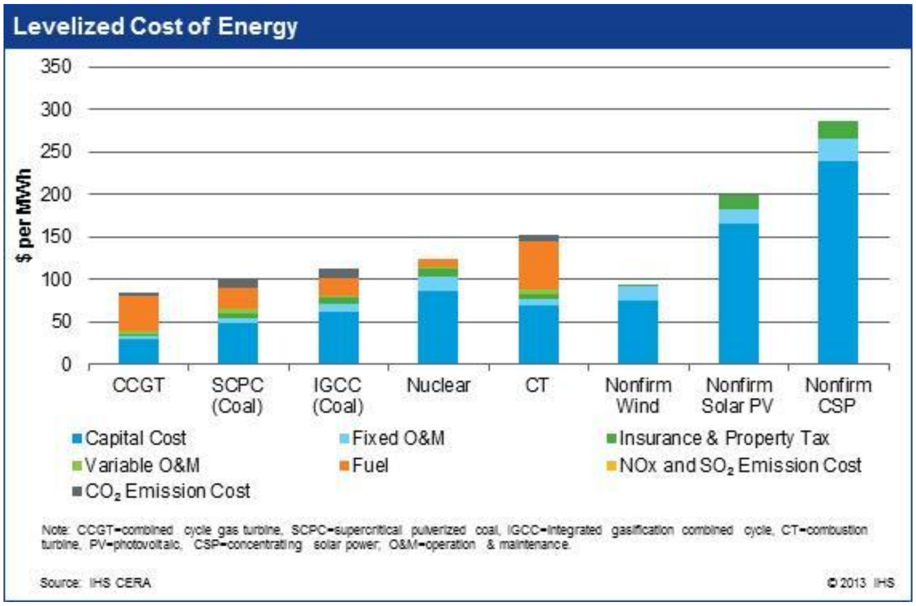
- Steam boilers use natural gas to heat water, making high pressure steam to drive steam turbines. These units can be used flexibly in a peaking and cycling capacity, although their start time is much slower than a CT unit. Many small and older units are in the process of being retired. Steam generation has efficiencies similar to CT units.

An integrated technology mix is considered best practice and still the least-cost power supply option today. That is, the lowest-cost source of power supply typically available to meet power customers' needs is an integration of CTs and CCGTs.

Natural gas-fired generators have the further advantage of lower capital costs than other traditional technologies and they can be built quickly compared with new coal and nuclear units. The prospect of sustained low natural gas prices is also increasing their competitiveness in terms of operating costs. IHS CERA estimates that the levelized cost of energy (LCOE) from a new CCGT is about $75 per megawatt-hour (MWh), significantly lower than competing technologies (see Figure VIII.5).

[123] The newest CCGT configurations boast thermal efficiencies of 60% or higher (i.e., LHV basis before plant auxiliary loads).

FIGURE VIII.5



Because there is no economic way to store large amounts of electricity yet, and despite many years of serious research efforts in advanced battery designs (e.g., high-density flywheels and compressed air applications), power must be generated in response to real-time fluctuations in demand. The outlook for increasing hydropower generation and pumped-hydro storage capacity is limited for environmental and cost reasons. Increasing the capacity of grid-scale battery storage is challenged by costs, but breakthroughs in technology could make it more cost competitive. According to a recent North America Renewable Power Advisory Market Brief *Battery Technology Charged with US Grid-Scale Role*, the US grid-scale battery market development surged in 2011, supported by government grants and regulatory policy support. IHS CERA estimates that capital costs for lithium-ion and flow battery costs would have to decline by approximately 20% to 50% in order to displace new gas combustion turbines as a capacity resource. Also IHS CERA estimates that the cost of grid-scale lithium-ion battery modules has fallen by over 60% since 2009 and it will continue to fall by another 25% by 2017. If such cost reductions are actually achieved, then grid-scale battery storage might effectively compete post-2020 with the dominance of gas-fired generation for real-time power market balancing services.

Natural gas and renewable generation

Flexible gas technologies provide a power source that can follow fluctuating power demand, help maintain power system reliability, and back up the growing amount of intermittent generation from renewable power resources, especially wind, because gas-fired generation is dispatchable. Even if ambitious and effective GHG, or CO_2, policy were adopted, combined with breakthroughs in commercial deployment of large-scale renewable technologies, grid reliability would likely still require gas projects to allow progress toward a less GHG-intensive future in the United States. In fact, the proliferation of renewable portfolio standards mandated by many states, and other policies that aim to reduce power plant emissions, mean that gas must compete with wind and other clean technologies to share new generation capacity in the years ahead.

Wind and solar power are expected to continue growing at a rapid pace, albeit from a relatively small base. On a national level, we expect the combined market share for wind and solar to more than double, from 3% of the generation mix in 2011 to more than 7% in 2020. This increase has implications for natural gas-fired generation which, because it is a dispatchable resource, acts as the primary source to firm the intermittent power supply from renewable sources and also to balance continuously changing power loads. Gas does this in response to hourly, daily, and seasonal fluctuations in the wind and solar resource (see the box "Texas power system case study").

Texas power system case study

The Texas power system provides a case study of lessons learned from integrating renewable power sources into the overall power supply mix. Wind development accounted for 99% of all renewable power additions since Texas implemented its renewable power requirement in 1999. In 2010, Texas had more wind capacity—9,317 megawatts (MW)—than any other US state. About 8% of Texas electric generation comes from wind turbines, and 80% of this capacity became operational in just the past five years. As wind capacity gained critical mass in the Texas power supply mix, the system's operating experience provided several important insights and lessons regarding integrating wind into overall power supply.

A lesson regarding the impact of wind on electric reliability occurred on February 27, 2008 in Texas. Weather forecasts led power system operators in Texas to expect a cold front to move into the region around 3:00 pm and increase aggregate consumer power demand, as well as drop wind production. Operators estimated wind output would drop by around 700 MW. When the cold front moved across Texas, it caused customer demands to go up by 2,500 MW (a 7% increase), while wind generation went down by twice as much as expected—1,400 MW (an 80% decline) within a three-hour period. This degree of short term unpredictability for two major variables in power system operations triggered a power system emergency to avoid major blackouts. The emergency required numerous actions—including starting up and ramping up natural gas–fired power plants—as well as cutting off power to some customers.

Reliability concerns are not just about the predictability of power supply, but also involve the availability of power supply. Dispatchable power resources are more reliable than renewable power sources. Reliability concerns become most critical at times of maximum power demand. For example, when Texas faced its 2010 peak demand for electricity of 65,776 MW, weather conditions meant that only 650 MW of wind capacity, out of the 9,317 MW of total installed wind turbine capacity, was available to help meet peak demand. As a result, the conventional fossil-fueled power plants were the resources that backed up the wind to keep the lights on and the air conditioners humming in homes and businesses. In February 2011, when weather conditions limited natural gas–fired generating plant availability, Texas experienced rolling power outages.[124] In addition, when heat waves drove new record peak demands in the summer of 2011, 80% of the wind capacity was not available for dispatch. Tight supply and demand conditions caused Electric Reliability Council of Texas (ERCOT) to sign contracts to activate mothballed natural gas–fired generating units instead.

The misalignment of wind generation with the timing, amount, and changes in aggregate consumer electric demand means that wind generating technologies alone cannot meet customer power needs. In Texas, natural gas–fired power plants are the conventional generation technologies that can do the things that wind plants cannot. These power plants are dispatchable—meaning they can start up and shut down, and ramp up and ramp down, to balance power system supply and demand. Therefore, integrating wind into the Texas power system to fit aggregate customer needs requires a roughly equivalent amount of conventional natural gas–fired capacity to firm up and fill in for the variations in wind output.[125]

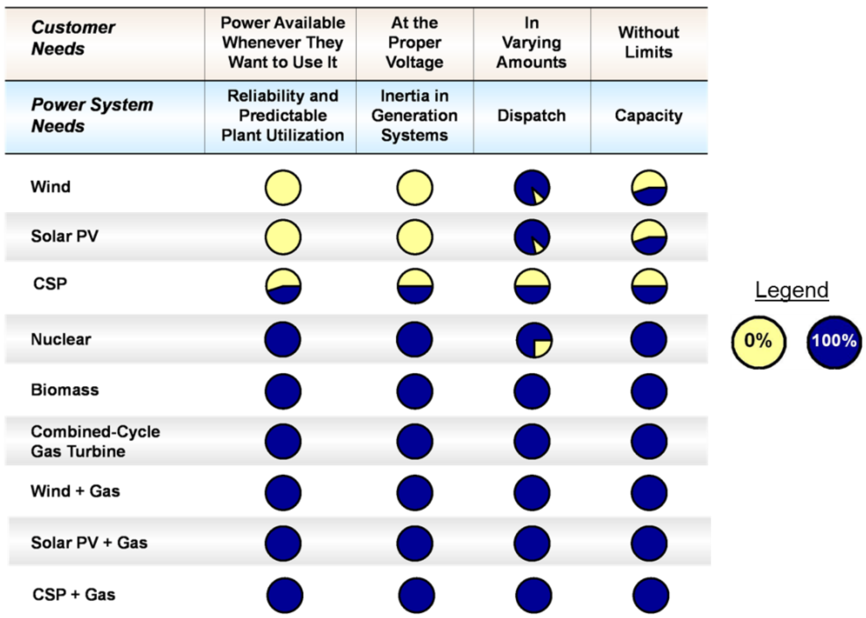
[124] Most of the gas generation was off line because it was not properly winterized, not because of lack of gas supply.

[125] For more detailed analysis, see the IHS CERA Private Report *Recalibrating Power Supply Cost Assessments: Accounting for Integration.*

Integrating various power supply technologies is not new. Most generating technologies cannot economically or operationally meet all dimensions of customer demands alone (see Figure VIII.6). However, by combining two or more generating technologies, the integrated supply option can meet all dimensions of demand. Natural gas-fired generating technologies could be proportionally integrated with wind turbines, for instance, to firm up the wind capacity, fill in the dispatchable energy requirements, and fully satisfy all dimensions of an increment of aggregate power demand. Natural gas-fired power plants provide the lowest-cost source of integration for intermittent renewable power generation technologies.

FIGURE VIII.6

Fitting Power Production to Customer/Power System Needs



Source: IHS CERA and IHS Emerging Energy Research.
10405-8A

Electricity demand growth

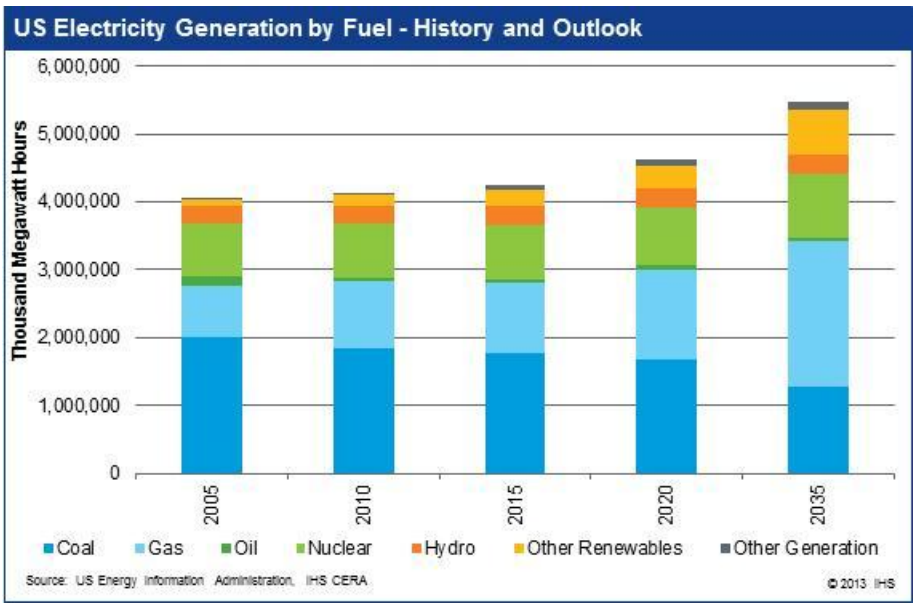
IHS CERA expects average US electric power demand to grow by 1.3% per year from 2012 to 2035. This long-term demand growth expectation is somewhat lower than historical growth rates primarily because of the effects of efficiency programs and increasing real retail power rates. Our outlook takes into account growth projections for household formation, population, income, employment, gross state product and gross state product of manufacturing, as well as changes in the real price of electricity for residential, commercial and industrial users, public policy and new appliance uses. Two additional specific drivers underscoring growth rate projections are the expectation for strong demand from the industrial sector and the continued proliferation of new electricity-intensive end-uses, such as large data centers.

IHS Global Insight expects the economic recovery to continue through the middle of the decade. The improving economic picture leads to rising real household income levels and continued innovations in electronics, resulting in new or expanded uses of electricity in residential, commercial, and industrial applications. IHS CERA expects steadily rising real retail power rates, averaging 0.8% per year. These rate increases are driven by both traditional capital investments in new generation capacity and the transmission and distribution systems, as well as by public policy initiatives. Public policy support for renewables and efficiency increases the real cost of electricity, which in turn supports the policy objective of slowing the rate of growth in power demand. However, we expect that state efficiency programs will fall short of achieving their full demand reduction targets. The resulting rate of demand growth means that the US power sector will still likely grow about one-third larger within two decades.

Implications for natural gas use in power generation

The natural gas share in the power generation fuel mix in any year or month varies depending on the price of natural gas relative to competing generation fuel prices in the given region. In the longer term, the investment decisions regarding fuels and technologies impact the capacity mix and, in turn, eventually transition the fuel mix. The unconventional natural gas revolution is reinforcing a two-decades-long trend toward an increased share for natural gas in the US power generation fuel mix (see Figure VIII.7).

FIGURE VIII.7



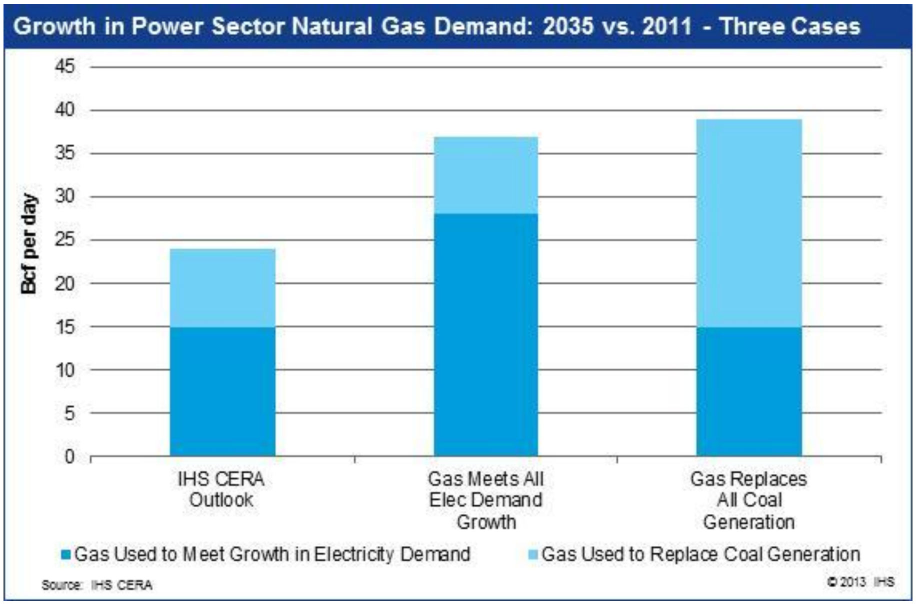
When translated into power sector demand for natural gas, IHS CERA expects an increase of approximately 24 Bcf per day by 2035, compared with 2011 (see Figure VIII.8). We estimate approximately 9 Bcf per day of increased natural gas demand from the expected retirements of coal capacity, and the remainder of the increase—15 Bcf per day—from overall growth in demand for electricity.[126]

Two hypothetical alternatives help put this outlook into perspective. First, if all growth in electricity demand from 2011 through 2035 were met by gas-fired generation (e.g., also from CCGTs with a heat rate of 7,000 Btu/kWh), total power sector gas demand would increase by 37 Bcf per day, that is 28 Bcf

[126] These calculations assume replacement power is generated with CCGTs with a heat rate of 7,000 Btu/kWh.

per day to meet growth in electricity demand and 9 Bcf per day to replace coal retirements. A second hypothetical scenario assumes that all coal-fired generation is eliminated and replaced by gas-fired generation. In such a case, power sector gas demand would increase by 39 Bcf per day, that is 15 Bcf per day to meet the increased electricity demand and an additional 24 Bcf per day to replace all coal-fired generation.

FIGURE VIII.8



The existing gas-fired fleet is not sufficient to: (a) provide the entire base load, cycling, and peaking generation required by US consumers and (b) replace all coal-fired generation. This means that all existing natural gas generating capacity could not be pressed into service to replace all existing coal-fired generation. Some capacity must be kept on stand-by to meet peak demand loads, therefore the capacity set aside to meet peak demand cannot also be used to meet base load demand. Moreover, much of the existing gas-fired generation fleet is not located in the right geographic areas to be able to replace *all* coal-fired generation. Substantial capacity additions to the gas-fired fleet would be required to meet growing power demand while also eliminating coal-fired generation.

Also note that much of the recent displacement of coal by gas in the generation mix has involved the most expensive and least efficient coal plants. However, many cost-effective coal-fired units remain available to dispatch before natural gas-fired plants, as will be the case during times when natural gas prices recover from their lower levels. Nevertheless, even if it is unreasonable to expect gas to completely displace coal in the power system, gas has an important role to play in reducing emissions from the power sector.

What could alter expectations about natural gas use in power?

There are of course many alternative paths the future could take that might affect the amount of natural gas-fired power that will be deployed in the United States, especially over the very long run. Three technologies stand out that might significantly increase or decrease future natural gas demand from the power sector: electric vehicles, solar photovoltaic technology, and the smart grid.

Electric vehicles

IHS CERA expects plug-in electric vehicles (PEVs) to account for about 6% of new light duty vehicle sales by 2035. In a “greener” scenario, it’s possible to see sales more than double that rate. Still this creates, at best, modest power demand growth—between 0.5% and 1% of total US power demand depending on the exact rate of sales. In either case, future PEV recharging requirements amount to a fraction of a billion cubic feet per day of natural gas demand for the power sector. We include this incremental demand for natural gas in our overall outlook for natural gas use in the power sector instead of counting it as natural gas used for transportation, as natural gas that is used to produce electricity for PEVs is only indirectly used for transportation.

The numbers are small for two reasons. The PEV share of the overall light-duty fleet remains modest over the next several decades, ranging from about 10 million to 22 million vehicles by 2035. The second reason is that electric motors are over 90% site-efficient and nearly four times more site-efficient than an internal combustion engine. This keeps the incremental electricity demand due to recharging at relatively modest levels.

Solar photovoltaic technology (and renewables)

Even with advances in competing power generation technologies, natural gas will play an important role in meeting long-term demand growth. Technological advances could play a role in reshaping the future power mix in a way that would favor more renewable investment over natural gas-fired capacity.

Most notably, additional technology breakthroughs in solar photovoltaic (PV) technology could lead to further capital cost declines and considerable gains in the photon-to-electron conversion efficiency. Advances have already reduced average prices for solar modules (i.e., crystalline silicon) by approximately 75% between 2009 and 2012. Substantial scale achieved in concentrating solar power (CSP) also may drive production costs down globally. Commercial advancements cannot be discounted in technologies such as enhanced geothermal systems and biomass. And lastly, offshore wind operating cost reductions are potentially achievable with greater scale and experience in this sector.

Though renewables may still remain costly relative to conventional fossil-based power, if there is an increasing value premium placed on power resources that are both clean and able to dispatch as baseload, their technological and commercial development will be encouraged through the long run.

Smart grid

Likewise, technological advances in the electric power grid, i.e., a “smarter grid,” promise both to enable the penetration of increasing amounts of intermittent renewable power and to shave peak power demand through more direct utility-consumer engagement. This vision of a smart grid suggests potential threats to conventional sources of power supply, including natural gas-fired generators, as renewables claim an increasing market share and as peak electric usage flattens with the introduction of real-time price signals to consumers.[127] Such perception of a smart grid *revolution*, however, is different than the technological *evolution* that is actually playing out across the country.[128] The potential implications of a move toward a smarter grid for power generators include:

- **Demand response will not replace natural gas-fired generators in renewables integration.** Expect natural gas and other conventional, dispatchable generation resources to continue providing critical firming services to the power grid. The size and frequency of demand response control that the smart grid enables will contribute only slightly to meeting the challenge of integrating intermittent renewables, including solar and wind resources.

- **Expect muted price signals for consumers and a modest slowing of peak demand growth.** Efforts to implement real-time pricing will be met with far more negative than positive consumer feedback. As consumers voice their preference for more stable and predictable power bills, expect a negotiated result with more muted price signals, such as time-of-use pricing structures with a modest price differential between on- and off-peak rates.[129]

Adoption of smart grid technology offers more tangible changes for utility or ISO operation of the power system – items that include reducing costs for metering and service connections/disconnections as well as improving the detection, isolation and restoration times associated with power outages - rather than for changing consumer behavior, reshaping power demand and integrating renewables. We expect that a continuing trend of incremental investments in advanced grid technology will play out over many years and gradually automate the power grid over the next two to three decades.

Gas/power harmonization

The growing role of gas in power generation will require even closer coordination between gas suppliers and power generators than exists today. Gas/power system harmonization has become a major focus of electric system regional transmission operators and the FERC, though reliability problems involving natural gas and power system operations date back several years. Shortage incidents, price spikes, and system disruptions have varied in severity, but such incidents have typically elicited some form of regulatory response. For example, in 2004, a winter cold snap in New England caused a spike in delivered natural gas prices and fuel deliverability issues for several gas-fired generators. The event helped precipitate development of emergency communication standards by the North American Energy Standards Board (NAESB) and adoption of those standards by the FERC.

More recently in February 2011, unusually cold weather in the southwestern United States led to unexpected shortages of power generation capacity. The generation shortages were caused, at least in part, by weatherization issues at power plants with the most severe impacts felt in the ERCOT market.

[127] Real-time pricing schemes confront end-users with the hourly or daily price of electricity from wholesale power markets in lieu of an averaged year-round flat rate.

[128] Adapted from IHS Inc. 2010 study on the smart grid's value proposition, *The "Smart Grid Narrative" and the "Smarter Grid": Revolution versus Evolution – Which Way Forward*.

[129] Unlike time-of-use rates which typically break out the price electricity into a few higher and lower cost blocks of time, real-time or dynamic pricing would expose consumers to hourly or daily variation in power prices. Such muted price signals translate into slower peak demand growth as opposed to a flattening of peak demand.

The shortages caused a chain reaction – power shortages impacted electric-drive compressors on the natural gas system, the resulting natural gas delivery problems exacerbated the power shortage, and triggered ERCOT's emergency system response, ultimately leading to about 4 GW of emergency electric load shedding. FERC responded with a February 2012 inquiry soliciting stakeholder commentary on the issue of gas/power interdependence. The inquiry was followed by a series of technical conferences across the country in 2012 and activities under the inquiry continued in 2013.

Two issues stand out in current discussions surrounding gas/electric harmonization – improving the coordination of daily operations between the two industries and insuring that pipeline infrastructure can service a growing fleet of gas-fired generators.

Aligning daily market schedules

Most Regional Transmission Operators (RTOs) operate power markets on a two-settlement system, meaning that they reconcile offers to buy and sell energy both on a day-ahead basis to suit forecasted market conditions, and in real-time as actual market conditions unfold. The electric day runs midnight to midnight (local time), but the time schedule for submitting offers and posting market results varies by power market RTO.[130] Generally speaking, scheduling for the day-ahead energy market begins in the morning before the applicable electric day, when market participants – both buyers and sellers – submit hourly generation and load schedules for the next day to the RTO. Once the day-ahead bidding window closes (between 11:00 am and noon local time for several markets), the RTO determines the dispatch schedule of resources needed to satisfy forecasted load on a least cost basis. It is in this *clearing* of the energy market that the RTO considers multiple factors such as live and anticipated system constraints, bilateral contracts, and the operating characteristics of the power supply generation resources. The results of the day-ahead process – hourly energy prices and resource dispatch schedules – are typically released to market participants during the afternoon preceding the start of the electric day.

Natural gas pipeline customers, or *shippers*, in natural gas industry parlance, under their service contracts must request or *nominate* the specific quantity of natural gas for delivery at each receipt and delivery point of along the pipeline on every day, whether the contract is for firm or interruptible pipeline service. The natural gas day runs from 9 am to 9 am Central Time across North America and scheduling happens on both a day-ahead and on an intraday basis. The market is most liquid during the first day-ahead nomination period, also known as the timely nomination cycle, where nominations are due by 11:30 am Central Time on the morning preceding the applicable gas day. There is an opportunity to adjust day-ahead nominations by 6 pm Central Time on the evening before the gas day begins. There are also intraday nomination periods where shippers can alter their schedules.

However the natural gas market day and the power market day are not perfectly aligned. Timely nominations for natural gas are due nearly a full day before the gas flows, and day-ahead generation energy market scheduling is finalized in the afternoon just hours before the power day begins. This scheduling difference means that gas-fired generators either purchase and schedule fuel delivery without knowing their power market energy dispatch status, or they bid into the energy market without knowing whether they will be able to successfully purchase and schedule natural gas. The mismatch in scheduling is manageable most of the time, but the situation can become problematic with potential reliability implications during peak natural gas demand, as well as during pipeline maintenance or emergencies. The independent system operator in New England (ISO-NE), for example, has a long record of incidents where gas-fired generators failed to respond to power dispatch instructions because they were unable to

[130] The gas day for North America has been standardized at 9 am to 9am Central Time.

secure natural gas fuel. ISO-NE recently received FERC approval to advance the settlement of its day-ahead energy market to better align with the natural gas market, allowing the ISO more time to mitigate the reliability risk in these circumstances. Similar measures may be needed in other markets to align the two.

Building infrastructure to support reliability

As discussed above, the power system is built, out of necessity, with reserve capacity. In contrast, natural gas infrastructure planning is done at the pipeline level by private natural gas pipeline companies after customer (i.e., shippers) commitments are clear. Individual customers transact firm natural gas pipeline capacity contracts based on their self-assessed needs. Long-term firm contracts serve as evidence of market need for pipeline expansion. Although there is no explicit requirement that natural gas pipelines maintain reserve capacity, gas LDC customers tend to build reliability into the system through the amount and type of capacity they purchase. For example, they tend to maintain a portfolio of gas supply contracts and pipeline/storage capacity contracts to meet the estimated peak needs of their aggregated customers.

The market for pipeline services, or transportation, consists of a primary and secondary market. Primary transportation includes two broad categories of service – firm and interruptible – with contracts signed by the pipeline and shipper. The effective cost of firm pipeline service is typically more expensive than interruptible pipeline service.[131] Firm service affords the shipper priority service for a set quantity of natural gas delivery between specific receipt and delivery points. Interruptible pipeline service, like firm service, is based on a specific quantity of gas delivery between two points. However, interruptible service carries a lower priority than firm service in that the shipper agrees to delivery only when capacity is available on the pipeline. Interruptible shippers face potential service interruptions during periods of high gas demand or pipeline system disruptions.

The appetite of power plants for firm pipeline transportation contracts varies across power markets. Gas-fired merchant generators in restructured power markets typically rely on lower cost interruptible pipeline service because cost recovery is far from certain for these power generators. The situation is far different in regulated power markets. Electric utilities tend more toward firm service contracts, as public utility commissions often allow the costs to be passed onto consumers through retail electric rates. Still increasing harmonization between the gas and power markets implies that new solutions may be required in regulated power markets too. Regulators and public policy makers may need to consider a variety of innovative cost recovery mechanisms that meet multiple needs locally in a new manner; each state must determine what innovative structure is best for its constituents.

As one example, while power capacity markets in the northeast are intended to compensate generators for reliability, the payments offer only short-term revenue certainty of one to three years as opposed to firm natural gas pipeline service contracts that are often ten years or longer in duration, thereby increasing the risk for a merchant generator if it subscribes to firm pipeline capacity. Furthermore, clearing prices and locations vary from auction to auction and market rules are typically silent on any requirement for firm fuel supply, thus gas-fired generators may not be incented to sign firm gas pipeline transportation contracts.

[131] Rates for interruptible transportation service are commodity-only and are set at the 100% load factor rate for firm transportation service. Unless the firm transportation service, which has a demand and commodity rate structure, is fully utilized, the effective cost of firm transportation service will be higher.

ISO-NE[132] is at the leading edge of this issue as natural gas becomes a larger part of the total generation mix and given ISO-NE's traditional position at the end of the long haul interstate gas pipeline system from the US Gulf. Proposed changes to its power capacity market aim at incentivizing reliability investments. ISO-NE's proposal would put in place a "pay-for-performance" structure that includes both penalties and incentives for power capacity resources during power system reserve shortage events. This structure results in a transfer of payments between performing and non-performing resources. Penalties and incentives would consider both the resource's performance relative to its capacity obligation and the severity of the system shortage. Alternatively some parties argue for federal or state mandates or directives to resolve opposing viewpoints between the gas and power industries, and in lieu of the current system that centers on developing power market rules with extensive stakeholder input.

The proposed structure could result in several different types of investments, including natural gas pipelines, dual fuel power generation capability (typically gas-fired generation with fuel oil, typically distillate, as a back-up fuel), demand response, and imported power from adjacent markets. ISO-NE's proposal will take time to implement as modifications require a lengthy stakeholder development and approval process. With some of the highest electric rates in the country, the New England market has every incentive to search for solutions that balance reliability with cost.

Balancing load

Higher regional natural gas prices during the winter in the Northeast and in the summer in the Southeast confirm that availability of gas supply is not solely a function of the resource base. Pipeline infrastructure to deliver the fuel to the point of consumption is as important a determinant to price as the availability of the gas resource base. Natural gas prices reflect both time demand requirements and place demand requirements.

Power plants bring a very large and unique load to the natural gas market. Some CTs can start and ramp up to full capacity in less than ten minutes. From a pipeline perspective, this is largely an instant increase, and the shutdown can be even faster. Power is a minute by minute and hour by hour market, as opposed to gas which tends to operate largely on a flatter daily cycle.

Unlike the power sector, intraday swings in natural gas demand do not need to be rebalanced instantaneously. The gas market balances intraday swings by varying line pack (defined as the quantity of natural gas in the pipeline at any given point in time). Because natural gas is compressible, line pack will vary as pipeline pressures vary. Pipeline pressure can be as low as the minimum pressure necessary to pump gas into an interconnection and to meet contractually required minimum delivery pressures. On the high side, pipeline pressures cannot exceed the authorized maximum allowable operating pressure. Although line pack can be used to balance intraday load swings, it must generally be replenished, or depleted, on a daily basis to be able to handle the next day's intraday natural gas demand swings. Natural gas storage is used to provide gas for replenishing line pack (i.e., through storage withdrawal) or depleting line pack (i.e., storage injection). Storage is frequently discussed as a key element to unlock additional system flexibility, and in particular, "high performance" or "multi-turn" storage that provides greater withdrawal and injection capability relative to working gas storage capacity.

As the amount of gas-fired generation on the pipeline network is increasing, so are the real time demands on the natural gas system. The gas generation capacity constructed over the coming decade will possess similar dispatch characteristics as the existing power generation fleet. And in any one region, power

[132] ISO-NE stands for Independent System Operator-New England and is an electric planning authority in the Eastern Interconnection responsible for moving electricity over large interstate areas.

producers tend to all look at new information from fairly similar weather and demand forecasts and make fairly similar corrections for the next day's operations. This means that when demand surprises occur (e.g., due to sudden changes in weather), a large gas consuming power sector might then look to turn on, or off, multiple gas-fired units at the same time. In these situations, gas pipelines will increasingly be unable to handle such swings in a no-notice fashion, or even notice fashion, and will require more real-time balancing of the source and sink by the gas shipper and power generator, respectively.

Gas LDC opportunities in central power generation

In 2011, approximately 25% of gas used by the power sector was delivered by gas LDCs, and the power sector accounted for nearly 15% of total gas LDC deliveries. As power demand for gas grows over the long-term, gas LDCs are anticipated to capture increasing power sector load. Under IHS CERA's baseline outlook for natural gas and assuming that each customer class continues to rely on gas LDC deliveries in the same proportion as today, gas LDCs will deliver 11.7 Bcf per day of gas to power sector customers by 2035, up from 5.4 Bcf per day in 2011, making them a more dominant class through time. However today's gas generators require pressures that many gas LDCs are not capable of delivering, although some gas LDCs do have high-pressure lines connecting parts of their systems.

In order for the gas LDC to be relevant to the power market, it must bring value to the customer. There are several areas of value to explore including: construction and operation of laterals between the interstate/intrastate pipeline and power plant (where this isn't done by the pipeline), construction and operation of metering and odorant systems, and operational balancing of natural gas fuel supply, e.g., such as no-notice swing services. What sort of value gas LDCs can provide varies by region and by the needs of the customers, and opportunities for gas LDCs may only exist if interstate/intrastate pipelines are unwilling or unable to provide these services at an economic price, or if the pipelines don't build or own the laterals.

Gas LDCs have expertise in construction of distribution pipelines and the real time operation of fuel delivery. Power plant developers, whether they are merchant or utility, generally do not have expertise in gas delivery systems nor the desire to operate them. Federal regulations dictate that any pipeline outside the fence of the power plant must comply with Department of Transportation standards for design, construction, operation, and maintenance. These are all functions for which the gas LDC or pipeline is ideally suited, the marginal cost is minimal, and the power plant operator generally lacks the expertise and the desire to perform that function.

Gas LDCs in general, and especially those with on-system natural gas storage, will be positioned to help play a balancing role. Even for power plants connected to the interstate pipeline directly, there is the opportunity for inclusion of the plant meter in a gas LDC's aggregate balancing arrangement. As the gas and power systems work together more closely, there will be opportunities for gas LDCs to provide additional services that simplify delivering gas to the power plant.

PUC policies in many states encourage gas LDCs to offer new services such as park and loan[133] to power

[133] Park and loan service is a common way for gas pipeline shippers to optimize their daily variance in offtake gas (demand) with their gas supply contracts thereby managing their portfolio on one pipeline or within one pipeline segment. A gas shipper can take less gas than originally scheduled and then "park" the excess supply inside the pipeline at times when demand is lower than anticipated. At times when gas demand is

generators that involve the use of existing facilities paid for by existing customers. PUCs generally require revenues from such services ultimately be used to reduce the rates of existing customers. Such policies may limit the net income upside for gas LDC stockholders from increasing sales to existing customers or selling new services using existing assets (see Chapter VI). Another way that PUCs protect existing customers is requiring that costs, especially for new services, be allocated away from existing customers with the gas LDC stockholders held at risk for achieving sufficient revenue to cover the allocated costs. Both approaches often deter gas LDCs from developing and offering new services that could benefit both new and existing customers in the long run.

Implications for gas LDCs

- The power sector has the largest potential increase in gas throughput, but gas-fired generation has a complex gas demand profile. In order for gas LDCs to be meaningful participants in this sector, they must provide continued value to power generators – such as helping to balance short term changes in power loads, providing storage, and constructing laterals.

- Gas LDCs have an opportunity to participate actively in managing real-time delivery of natural gas, i.e., gas/power harmonization, given their pre-existing portfolios of gas, and to work with PUCs for the appropriate regulatory modifications.

- From a climate change perspective, replacing coal-fired power generation with gas-fired generation would lead to lower CO_2 emissions. Gas LDCs should be important participants in this dialogue.

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higher than expected, pipeline shippers can adjust their offtake upward, in effect borrowing (“loaning”) from the pipeline. See also http://www.ferc.gov/market-oversight/guide/energy-primer.pdf, accessed 13 August 2013.

Chapter IX: Combined Heat and Power (CHP)

In Brief

- Combined heat and power produces electricity and usable heat from a single source of energy at the site of use, achieving high overall energy efficiency and avoiding the losses and costs associated with transmission and distribution from the central power grid. While CHP typically has high initial costs, electricity generated on site can reduce purchases of electricity and generate cost savings over time.
- For certain types of customers, benefits may include high energy efficiency, energy cost savings, ability to count CHP in Renewable Portfolio Standards and Energy Efficiency Resource Standards, and less reliance on the power grid.
- Regions where CHP is likely to be successful include those with high electricity prices relative to natural gas prices, and in states that have a combination of policies that facilitate permitting and construction and electricity sales to other end-users or to the grid.
- The challenge of high initial investment cost is the single largest barrier to more widespread acceptance of CHP in the small- and medium-scale markets in the United States. More projects may succeed if they receive revenue from the sale of electricity to the grid or are aggregated in investment vehicles.
- Particularly for small scale CHP to grow, new business models are required that better align the interests of customers, regulators, energy suppliers, and manufacturers/distributors of CHP technology.

Combined heat and power, also known as cogeneration, is an efficient approach to generating electricity or mechanical power and useful thermal energy from a single fuel source at the point of use. Instead of purchasing electricity and then burning fuel in an on site furnace or boiler to produce thermal energy, a facility can use CHP to provide these energy services in one energy-efficient step. As a result, CHP can provide significant energy efficiency and environmental advantages over separate heat and power. For optimal efficiency, CHP systems must be designed and sized to meet the user's baseload thermal demand.

In many cases, CHP technology can be deployed quickly, cost-effectively, and with few geographic limitations. When a power generation unit is combined with a heat recovery system, it becomes a combined heat and power plant that can have higher total energy efficiency than producing (or purchasing) power and heat separately. Because electricity is produced on site, it also avoids the losses and costs associated with transmission and distribution from the central power grid, estimated at about 8% nationally.

CHP is not new. It was common in the early years of the electric power industry, but over time gave ground to centrally generated power, which enjoyed great economies of scale and therefore lower cost.

CHP received a boost in 1978 when the Public Utilities Regulatory Policy Act (PURPA) was enacted, requiring electric utilities to purchase excess electricity produced by cogeneration facilities that met minimum efficiency standards. In response to PURPA and a number of tax incentives passed at the same time, CHP capacity grew from 12 gigawatts (GW) in 1980 to 66 GW by 2000, with another round of modest growth thereafter.[134] Today CHP capacity is estimated at 82 GW[135], of which 87% is industrial (primarily in chemicals, petroleum refining, paper and food processing) and 13% is commercial.[136] Viable commercial entities may be hospitals, universities, military installations, prisons, nursing homes, etc. The residential and small commercial market is virtually nonexistent in the United States, with only a few hundred residential installations. This segment is generally referred to as the microCHP, or mCHP, market with unit capacities of less than 50kW.

There is renewed general interest in CHP in the United States today. Some of the major drivers for growth of natural gas-based CHP are the advantageous price outlook for natural gas, state or federal incentives (over 20 states recognize CHP as part of their renewable or alternative energy portfolio standards or energy efficiency resource standards), efforts to increase the reliability of the power grid, remote sites for oil and gas exploration, and energy self-sufficiency for crisis management. States where gas-based CHP is likely to be successful include those that have a combination of policies that facilitate permitting and construction, potential for electricity sales back to other end-users or the grid, and high spark spread values.[137]

Natural gas is the fuel of choice for existing CHP, with 71% of capacity consuming 3.4 Bcf per day of gas.[138] In 2012, according to EIA, the industrial sector used 1.7 billion cubic feet per day of natural gas for electricity production, with an additional 1.5 Bcf per day consumed for useful thermal output. The commercial sector used 0.1 Bcf per day of natural gas for electricity production and 0.1 Bcf per day for useful thermal output.

In the US industrial sector, retrofits of existing steam and/or power plants have largely been accomplished. A recent study[139] estimated the maximum US *technical* potential at 125 GW for medium-scale CHP (units with capacities ranging 1-100 MW that are likely to be connected to gas LDCs). However, because this estimate does not consider whether an installation is *economically feasible*, it declines to only 6 to 17 GW when translated into *strong economic potential*, defined as having a simple payback period of less than five years for a CHP project and under a very specific set of conditions. The base case translates into incremental gas use of 1.8 Tcf per year, with potential up to 2.7 Tcf per year under certain scenarios.

Customer segmentation is important as well. Different sectors will view CHP opportunities differently and have different priorities for allocating internal capital among project investments. For example, industrial manufacturers must allocate capital to the areas of highest risk-adjusted return. By contrast,

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[134] ICF International, *The Opportunity for CHP in the United States*, 2013.

[135] By comparison total US net summer electric power generating capacity was 1,051 GW at end -2011.

[136] *CHP Installation Database*, developed by ICF International for Oak Ridge National Laboratory and the US Department of Energy; available at http://www.eea-inc.com/chpdata/index.html, accessed May 16, 2013.

[137] A spark spread is the mathematical value of theoretical gross margin of a gas-fired power plant from selling a unit of electricity after purchasing the fuel. Spark Spread = Price of Electricity - [(Price of Gas) * (Heat Rate)] = $/MWh - [($/MMBtu) * (MMBtu / MWh)]. The heat rate accounts for the thermal efficiency of the power plant in converting fuel into electricity.

[138] US Energy Information Administration, *Electric Power Monthly*, February 2013. 'Independent power producers' are tracked in another category by US Energy Information Administration; for comparison purposes please note that IPPs consumed 13.7 Bcf per day of natural gas during the same period.

[139] ICF International, *The Opportunity for CHP in the United States*, 2013.

institutions like universities may plan over longer time horizons and may be more tolerant of some investment risk that an industrial entity could not consider. Therefore, a CHP project with a five year payback period may look attractive to an institution but remain unacceptable to an industrial customer.

President Obama's Executive Order, *Accelerating Investment in Industrial Energy Efficiency*[140], of August 30, 2012, is intended to promote American manufacturing by increasing coordination among federal agencies to facilitate investment in and removal of barriers to new CHP installations. It targets the addition of 40 GW of new capacity by 2020, although there is no associated funding to accomplish its goals.

> *"Instead of burning fuel in an on site boiler to produce thermal energy and also purchasing electricity from the grid, a manufacturing facility can use a CHP system to provide both types of energy in one energy efficient step. Accelerating these investments in our Nation's factories can improve the competitiveness of United States manufacturing, lower energy costs, free up future capital for businesses to invest, reduce air pollution, and create jobs."*

Furthermore the benefits of the Order as identified by US Department of Energy are new capital investments on the order of $40 to $80 billion in plant and equipment, as well as energy saving to American manufacturers and businesses of some $10 billion each year equal to one percent of all energy use in the United States, including an emissions reduction equivalent to taking 25 million cars off the road.

Benefits of CHP

For certain types of customers, CHP offers the benefits of:

- High energy efficiency
- Cost savings
- Less reliance on the power grid

A key benefit to CHP is consumer cost savings over its lifecycle. Electricity and heat generated on site can lead to cost reductions in purchased electricity and thermal energy if procured off site. These costs savings can be substantial, especially with large systems and if the price of purchased electricity offset is high.

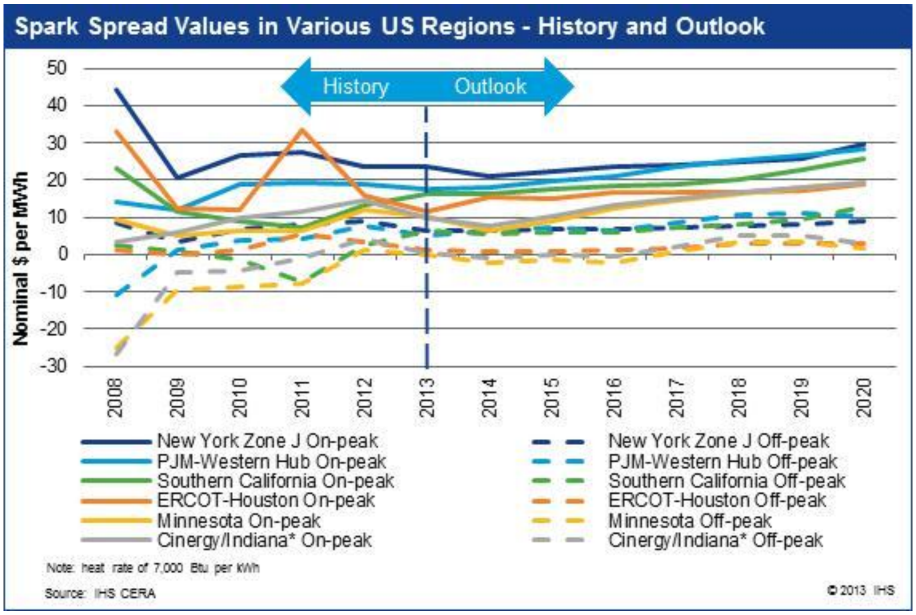
The largest energy savings are likely to be in regions with the largest electric to natural gas price differences. The spread between wholesale power and wholesale natural gas prices is referred to as the 'spark spread', and it can vary considerably among regions as shown in Figure IX.1. Using wholesale prices to evaluate potential future savings in retail prices can be the first layer before more in-depth analysis, so examining spark spreads may highlight regions with customers that may be candidates for CHP. For example over the past five or so years, New York Zone J has tended to have the highest spark

[140] http://www.whitehouse.gov/the-press-office/2012/08/30/executive-order-accelerating-investment-industrial-energy-efficiency.

spread values almost every year during both on- and off-peak time periods. High spark spreads have also occurred in the electric power region known as PJM-Western Hub and in southern California. In addition,

IHS CERA anticipates that retail electric power prices will rise faster than retail natural gas prices over the long term, which if realized would tend to accentuate the benefits of CHP systems.

FIGURE IX.1



Another potential advantage of CHP includes higher overall energy efficiency that comes first from the cogeneration of heat and power on site, and second from the avoidance of the losses associated with the transmission and distribution of moving power from a central generating unit to an end user site. For this reason, a number of states allow CHP to be counted in their Renewable Portfolio Standards or Energy Efficiency Resource Standards. Natural gas-fired CHP can give rise to large energy savings when operated continuously due to the ability to fuel the CHP unit throughout each day and season, as opposed to intermittent renewable energy resources such as wind and solar which have inherently lower capacity factors.[141] If a CHP unit runs at higher capacity and overall efficiency compared to a more CO_2-intensive grid electricity source, it will consume less fuel and produce fewer greenhouse gas emissions.

Some states discriminate based on the fuel source, e.g., natural gas or renewable, whereas others do not. For instance, New England and Mid-Atlantic states are among those that count gas-fired CHP as a Tier II RPS.[142] In the case of Maine, if capacity is less than 100 MW, gas CHP counts for the state's "existing" renewable standard, but not the "new" standard. In North Carolina, any size or vintage CHP counts toward RPS. In North and South Dakota, where goals are voluntary, any electricity generated from unused waste heat from combustion or other processes (without additional combustion) from a system whose primary purpose is not electricity generation counts. Colorado, where goals are mandatory, has the same terms as the Dakotas, except the generator must be less than 15 MW. Other states designate portions of their Renewable Portfolio Standards as carve-outs for CHP that also is distributed generation (DG) that

[141] Cogeneration and Onsite Power Production, *Will the coming Texas power crunch create another CHP boom?* January-February 2012.

[142] Energy from renewable sources such as wind, solar, geothermal typically meet requirements for Tier I Renewable Portfolio Standards, while depending on the state, other resources such as CHP and waste heat may qualify as Tier II Renewable Portfolio Standards but typically in limited quantities.

can only be met by renewable sources of energy. Removing such fuel biases in RPS and in other state subsidies, such as feed-in tariffs, could help support the growth of natural gas fueled DG. DG refers to on site power generation that runs in parallel with the central electric power grid and it may or may not be interconnected with the grid.

Many types of DG can increase reliability during emergencies, such as storms or other disruptions, when used as backup for the power grid. Such benefits were illustrated in the performance of the gas fueled CHP system at the Long Island Home, a member of the North Shore LIJ Health System, during Hurricane Sandy in October-November of 2012. During that time, the 1,250 kW plant (five-250 kW units) isolated from the grid according to protocol and was able to generate about 224,000 kWh of power over 15 days, providing power to its own facilities as well as over 400 homes, and importantly, allowing the Long Island Home to maintain a 24-hour emergency operation center for the entire North Shore-LIJ Health System. Some police and fire department responders and local residents were able to use charging stations for medical and other equipment and also to refrigerate medications.

Isolating from the grid and entering islanding mode is an important capability. Many small and medium sized facilities do not have black start capability – the ability to isolate themselves automatically from the grid by shutting down and then restarting under their own power source. Adding black start capability to some of the small scale CHP units such as microturbines can drive the price tag up considerably, although backup generators do have this feature.

Some parties are focused on trying to link distributed generation into the smart grid vision in order to make the grid more reliable and robust in delivering electricity. If ever developed on a large scale over the longer-term, distributed generation may offer a unique tool to balance congestion in electric and gas grids by reducing the growth in the daily power peak, after technology evolves to lower costs to an acceptable level.

Challenges

CHP has met with success in certain US industrial sectors such as petroleum refining, chemical processing and pulp/paper processing and is a niche market in the large commercial sector. Viable commercial entities appear to be hospitals, universities, military installations, prisons, nursing homes, etc. It has encountered severe challenges in penetrating the small- and medium-scale residential and commercial markets.

High costs (equipment, installation and maintenance costs) are the single largest barrier to more widespread acceptance of CHP in the United States. As long as high costs persist, growth in CHP is likely to be limited. Complicating matters, individual project economics vary considerably and depend on a myriad of local factors that make it hard to generalize about installing CHP.

Some of the challenges are because CHP is:

- Highly site-specific; pre-existing systems for power and thermal generation may give rise to site and space constraints when they are retrofitted. New or expanded facilities may avoid these constraints.

- Highly sensitive to load factors and whether the system is used for both heating and cooling applications, or only for heating or steam.

- Contingent on the vagaries of local permitting requirements. Natural gas in CHP applications may provide improved environmental permitting, especially compared with coal, oil, or biomass.

- Dependent on local natural gas and electric power rates.
- Typically subject to declining electrical efficiency as the unit size decreases.

Cogeneration economics decline quickly when the thermal load is not constant, and in many applications the plant sizing and flexibility are not aligned with the end user's power needs on site. This has ultimately prevented many existing and potential end users from going completely off-grid.

On a cost basis, small-scale generation cannot compete with power from central stations. The least-cost scale for power generation, which bulk power suppliers are able to exploit, is hundreds of times larger than the on site needs of individual consumers. In other words, a central station power generator can supply the needs of hundreds of microgrids at lower cost than an individual CHP system. EPA data presented in Table IX.1[143] show the impact of economies of scale by comparing a 1 MW capacity gas turbine (suitable for a medium commercial facility) with installed costs of $3,563/kWe declining by 70% for a 40 MW capacity (very small) gas turbine power plant to $1,054/kWe. Increasing scale even further will tend to decrease costs as well.

TABLE IX.1

Selected Costs and Performance Characteristics of CHP Technologies

	Steam Turbine	Recip Engine	Gas Turbine	Microturbine	Fuel Cell
Typical Capacity (MWe)	0.50-250	0.01-5	0.50-250	0.03-0.25	0.005-2
CHP installed costs (2012$/kWe)	467 - 1,195*	1,195 - 2,390	1,054 - 3,563**	2,607 - 3,260	5,432 - 7,062
O&M costs (2012$/kWhe)	< 0.005	0.010 - 0.023	0.004 - 0.012	0.013 - 0.027	0.035 - 0.042
Power Efficiency	15-38%	22-40%	22-36%	18-27%	30-63%
Effective Electrical Efficiency	75%	70-80%	50-70%	50-70%	55-80%
Overall Efficiency	80%	70-80%	70-75%	65-75%	55-80%
Typical power-to-heat ratio	0.1-0.3	0.5-1	0.5-2	0.4-0.7	1-2
Start-up time	1 hr -1 day	10 sec	10 min - 1 hr	60 sec	3 hrs - 2 days

*0.5-15 MW size for steam turbines in CHP applications.

**1 - 40 MW size for gas turbines in CHP applications.

Source: US Environmental Protection Agency Catalog of CHP Technologies, December 2008. Costs converted from 2007 $ to 2012 $ using the US GDP deflator from US Bureau of Economic Analysis.

Among microCHP technologies of less than 10 kW of capacity, fuel cells have the highest installed costs ranging from $5,432 to $7,062/kWe for capacities of 2 MW and 0.005 MW respectively as referenced in the EPA study. Installed costs for the microturbines were substantially less at $2,607 to $3,260/kWe (for 0.25 and 0.03 MW capacity respectively), and also lower than the smallest of the gas turbines, however microturbines have operation and maintenance (O&M) costs on the order of two to three times higher than the gas turbines due to their more complex equipment. While the steam turbine economics are somewhat more attractive, that technology does not possess the fast start up time of the gas turbines which has become a critical feature to dispatch into organized power markets.

[143] US Environmental Protection Agency Catalog of CHP Technologies, December 2008. Cost data are from US Environmental Protection Agency for 2008, inflated to 2011 $ using the US GDP deflator from the US Bureau of Economic Analysis.

The large scale CHP market is mature and well developed in the United States, but the microCHP market is not. For large scale, American Council for an Energy-Efficient Economy (ACEEE) concluded that investment payback periods in 2010 ranged from 1.5 to 12 years with 4 to 6 years the most typical range.[144] That study also concluded that industrial companies viewed anything longer than one-year payback as an unattractive investment due to its riskiness and proximity to the weak economic environment of the Great Recession. Prior to the recession, three- to five-year paybacks were more acceptable to industrial companies.

For small scale units, data are particularly difficult to find. Many units have not been installed long enough to measure the economics. Since the EPA study, other recent observations[145] of microCHP suggest even higher costs with equipment quotes for packages up to 10kW on the order of $4,000-10,000/kWe for the gas turbines and $10,000-12,000/kWe for the fuel cells. Because of the early market state for small capacity machines, installation costs have been reported to be high - from around 30%, and even up to 300% in some extreme circumstances, of the equipment cost. Such data suggest paybacks on the order of 15 to 35 years depending on how much of an end user's needs are met by CHP and how well the units are operated and maintained. Given such high price tags, these units often appeal to consumers in search of a premium solution beyond a traditional heating, ventilation and air conditioning system.

Another factor limiting their growth is the lack of dedicated distribution networks for certain product lines. MicroCHP manufacturers of 5 to 10 kW certified gas turbines available in the United States include Marathon Engine Systems, Yanmar Systems, Capstone, and a 1.2 kW machine from American Honda Motor Company was formerly on the market. Clear Edge Power and Bloom Energy offer fuel cells in the US market.

How to overcome some challenges

For CHP to grow, regulatory and policy changes are likely to be necessary, particularly at the state level. Some, but not all, states include gas CHP in energy efficiency, renewable portfolio standard programs, and programs that allow and fairly compensate for power sales and services. However it is important for all policy makers to recognize that they may be biasing outcomes against gas CHP and in favor of renewable CHP or other technologies unintentionally. Attempting to include quantification of the benefits from intangible items into metrics such as the return on investment may also help push the odds toward outcomes that favor gas CHP if concepts such as energy efficiency, independence from the grid, greenhouse gas reductions or petroleum displacement are purposely included.

Rate Design for Distributed Generation (DG)

Full cost recovery for power utilities is critical to ensure viability of the electric system and avoidance of cross-subsidization by non-participating customers. In determining electricity rates, utility regulators rely on the principle that customers should pay for the costs of the services they receive from their utility and the electric power grid and not pay for the costs of services provided to other customers. Full cost recovery is also one of the critical requisites for the design of standby rates that are typically assigned to distributed generation; regulation options vary by market structure and different considerations are paid to vertically-integrated utility service regions compared with organized markets and utilities with wires-only service.

[144] American Council for an Energy-Efficient Economy, *Challenges Facing Combined Heat and Power Today: A State-by-State Assessment*, September 2011.

[145] Interviews by IHS Inc.

DG customers also have the potential to provide some benefits to the grid. These may include the avoided cost of upgrading generation, transmission or distribution facilities. The value of on site distributed generation is a function of its generation capacity, fuel and the purchased energy that may be offset, the dependability of the generation resource, and the value of the transmission and distribution resources that may have been utilized absent the distributed generation system. These values may exist whether electricity export to the grid is taking place or not.

Some gas CHP installations also have the ability to sell power back to the grid, if they are configured as distributed energy resources. CHP plants are typically sized to meet the power and thermal needs of the installation, rather than being designed to sell power to the grid, but opportunities often exist to sell excess power to the grid. The value of energy generated is based on the time of day that it is produced and also its probability of being produced as planned (i.e., its reliability).

Recent attention is focused on the ability of rooftop solar installations to export power to the grid, compensating solar owners for sales of power to the grid. Many of states in fact credit the solar owners at the full retail rate of electricity for all of their power sales to the grid. In principle, this means that a customer with distributed energy resources can offset or deduct the electricity generated on their property against the electricity purchased from the grid. The customer's meter increases when electricity is purchased from the grid and, then in effect, runs in reverse when distributed electricity generation is sold to the grid. If the revenue stream generates enough electricity to offset all of the purchased electricity, it is conceivable that a customer could have an effective zero dollar bill.

Current methods of net metering for customers with DG systems generally fail the basic principles of full recovery since customers are credited for the power they sell to electric utilities at the full retail rate (which includes all of the fixed costs of the poles, wires, meters, advanced technologies, and other infrastructure that makes the grid safe, reliable, and able to accommodate distributed generation systems), but they avoid paying many of the fixed infrastructure costs associated with the services they receive from the grid. Thus, many distributed generation customers are able to sell energy to the grid at prices that are greater than the avoided variable costs of power. In such situations, retail price net metering may effectively transfer costs to non-distributed generation customers or create financial risk for the electric utility to not recover its fixed costs.

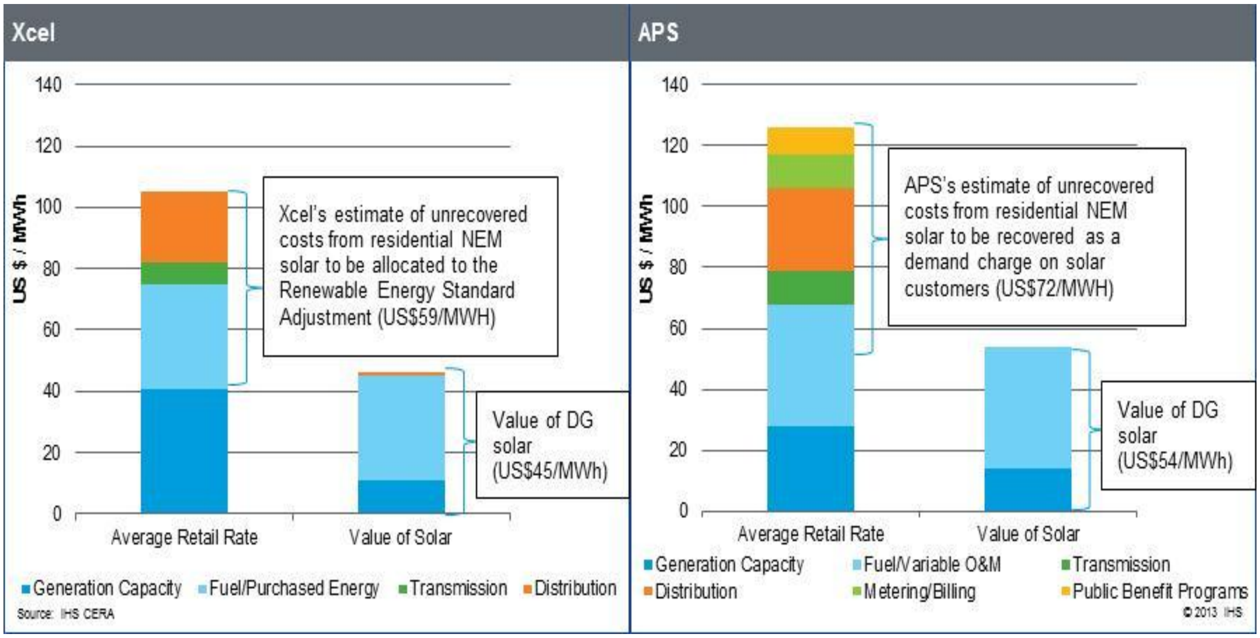
Different approaches are being proposed that rely more on avoided costs rather than full retail rates that in fact may also hold potential for CHP to grow, if the policy playing field is leveled for all distributed generation technologies. A number of US electric power utilities in four of the top six distributed solar generation states (Arizona, Colorado, New Jersey and California[146]) have recently pointed out flaws in the use of full retail rates that make it unsustainable over the long-term. Figure IX.2 shows recent estimates by two electric power utilities as they petitioned their state PUCs for full recovery of the costs incurred during servicing of solar customers as described above.[147] For each company, the bar on the left represents their estimates of the average retail rate received by the residential solar customers for power sold to the grid; the bar on the right represents their estimates of the value that the grid receives when it purchases the solar power. The electric power utilities are seeking to recover the difference between the two bars, i.e., value paid minus value received.

[146] http://www.eei.org/ourissues/finance/Documents/disruptivechallenges.pdf.

[147] IHS Emerging Energy Resource, States debate whether to wind back net metering, 11 September 2013.

FIGURE IX.2

Alternative Approaches to Estimating Unrecovered Costs and the Value of Solar Net Energy Metering



Note: Net energy metered (NEM) solar customers' effective retail power prices tend to be higher than the average retail rate due to higher power consumption. These average retail rates do not include taxes. Source: APS, Xcel, IHS

Customer-sited CHP DG may be able to provide higher net value to the grid than customer-sited solar DG due to the fact that it is a dispatchable resource and may rely less on ancillary and balancing services that the grid provides throughout the day, i.e., CHP's estimated right hand bar may be higher than the estimated value of distributed solar generation. As states' policies are reevaluated, this feature of CHP DG should be considered. Also if the goal is to achieve public policy benefits at lower costs and rates, CHP DG may be more valuable than rooftop solar in some cases.

The design of standby rates also has challenged many CHP projects. Their purpose is to recover the cost of providing service during planned or unplanned outages of the CHP system, or for supplemental service when required. However they tend to reduce the cost savings that a CHP project generates by lengthening the potential payback period and they sometimes stifle overall project economics. There may be options or features that regulators can consider that do not discourage CHP and where the utility can provide distributed generation customers with different options to avoid charges when costs are not imposed on the power system.

Low and stable gas prices from the widespread availability of domestic natural gas supplies also help encourage adoption of gas-fueled CHP technology, although savings from gas prices are often insufficient to overcome the high initial costs in the medium- and small-scale markets. Government subsidies could help to lower costs, but just as important is the removal of any regulatory barriers at the state and local level. Texas serves as a good example of ongoing efforts to remove obstacles to large scale CHP (see the box "CHP directed at Texas power/water crunch") in the wholesale markets.

CHP directed at Texas power/water crunch

Texas leads the nation, by a very wide margin, in installed CHP capacity at 17 GW, due to its concentration of chemical plants, refineries and other industrial facilities that are large users of electricity and process steam. CHP supplies about 20% of all of Texas' power from 124 facilities. Ongoing concerns in Texas about power resource adequacy and water shortages over the past several years have led the state to enact a series of legislative rulings that are anticipated to facilitate growth in gas-fired CHP. In June 2013, the governor removed a long standing regulatory barrier for CHP by signing House Bill 2049 clarifying language in the Texas Utility Code to allow CHP facilities to sell both power and heat to the same customer, or to multiple customers, in proximity of the CHP plant. In the past, they could only sell electricity to one customer. This change helps to level the playing field to enable wholesale power sales by CHP owners as compared to other power generation technologies.

In another important ruling, legislation adopted in September 2012 will also facilitate growth in new CHP installations by simplifying the air emission permitting process for stationary natural gas engines and turbines used in CHP. In response to the ruling, the Texas Commission on Environmental Quality (TCEQ) issued a permit by rule (PBR) as an alternative to the existing standard permitting process. The new PBR authorizes emissions from natural-gas fired CHP units up to a capacity of 8 MW without additional emission controls, or up to 15 MW with additional controls. Operators are still required to monitor, test, and keep records to allow TCEQ to verify compliance. Also for the larger units, a more stringent NOx emission standard was adopted of 0.7 lb NOx/MWh and a requirement for an oxidation catalyst control device in order to maintain compliance with NAAQS. The PBR is perceived to be an easier, faster and less costly way to authorize air emissions from CHP facilities, simultaneously improving the flexibility of the electric power grid.

Also in July 2013, House Bill 1864 instructed the State Energy Conservation Office to issue guidelines on how to properly conduct a CHP feasibility study prior to planning and renovating government facilities that are deemed critical for disaster preparedness and emergency response.

New business models

Particularly for small scale CHP, new business models are likely to be required that better align the interests of customers, regulators, energy suppliers, and manufacturers/distributors of CHP technology. In response to these needs, some CHP manufacturers and suppliers may wish to act as the financing intermediaries and choose to own and operate the CHP equipment, and selling power, heat, and steam at a discount to retail rates to the end user over a long contract period. Solar City, which has found some success in rooftop solar installations, may be one business model to examine and possibly emulate.

Perhaps a pooled solution for small scale CHP investment

There are two primary barriers to entry for CHP in the commercial and residential markets - the high initial investment cost and an uncertain return on investment. Typically CHP has a high initial investment requirement (capital and installation costs) and long-term payback period relative to competing alternatives in a setting where entities need to allocate scarce capital. The second barrier to entry for CHP in the commercial and residential markets is the uncertainty regarding its return on investment. CHP's economic performance is extremely sensitive to the thermal load requirement of the application and therefore also sensitive to the price of natural gas. To date, CHP has been most successful penetrating industries that have fairly high and constant thermal requirements, industries such as petroleum refining, chemical processing and paper processing. Large, steady thermal load requirements are less common in residential and commercial applications; viable commercial candidates may be hospitals, universities, military installations, prisons, nursing homes, etc.

An initial investment in a CHP system is recovered by the savings from purchasing less electricity off the grid over time which is partially offset by additional purchases of natural gas fuel to feed the system. In economically successful applications, the electric savings will exceed the sum of the initial investment, gas fuel, and operating costs in line with, or in excess of, the expected rate of return within a designated time horizon. Should gas prices increase or operational parameters vary too much, the expected savings may not be realized and the rate of return on investment can easily decline. Hence, CHP in residential and commercial applications tends to have a wider band of possible outcomes around an expected rate of return compared to typical utility investments. In fact the price of the natural gas commodity is typically passed through to customers meaning a traditional gas LDC's rate of return is largely immune to changing natural gas commodity prices. Hence the risk profile of a CHP investment in residential and commercial applications is considered higher than the risk profile of a typical gas LDC investment.

Some parties have argued that policymakers could simply allow gas LDCs to offer financing assistance for the initial investment to be recovered over a longer time horizon (so that the stream of payments are smaller in size and more digestible for the customer) or to allow the gas LDC to place CHP investments into rate base.

In actuality, the situation is more complicated than either two of the prescribed solutions, since the risks described do not disappear. In the case of the consumer paying back the initial CHP investment over a longer time period, the gas LDC holds a receivable and the customer holds a liability, but the risk of default, or nonperformance, for the gas LDC would increase due to the longer time horizon over which the customer can choose to either a) continue to make payments as planned or b) cease payments after sale of the property containing the CHP asset or during a distressed financial situation. Even in the case of allowing the CHP asset to enter into the gas LDC rate base, the same risks of default or sub-economic performance remain; they are only transferred from the customer's balance sheet to the gas LDC's balance sheet. Other issues to be resolved include placement of the equipment on a customer's property, rather than on the gas LDC's property.[148]

One advantage of the traditional gas LDC is its access to a lower cost of capital than its industrial, commercial or residential customers. The gas LDC's structure and mandate to serve granted by the state PUC increase the certainty of recovering an investment at the planned rate of return, distinguishing rate base investments as safer than many other types of investments. Transferring higher risk profile assets into rate base could jeopardize a gas LDC's credit rating and increase its cost of capital – neither of which are likely to be acceptable outcomes.

To allow CHP into rate base, entirely new structures might be devised in concert with state PUCs that are acceptable to all parties and also guard against stranded costs for the gas LDCs, yet still attract new capital to CHP investments. One solution might be to combine aspects of different standard investment practices and vehicles possibly facilitating penetration of CHP in residential and commercial applications. For instance, aggregating hundreds or thousands of diverse CHP customers and projects could achieve scale and may allow diversification of risk creating a more attractive risk profile than any one individual customer. A benefit of diversification includes reducing volatility to maintain an average return and is a tenet of modern portfolio theory common to many industries such as health and life insurance, credit card portfolios and some equity and bond market instruments. Secondly, risk might be reduced further if investments and customer contracts pertaining to the CHP projects of multiple gas LDC jurisdictions are pooled into a single entity. In such a situation each gas LDC would contribute funds into the investment vehicle and hold a proportional share of the receivable; customers have liabilities and make payments to the fund; and each gas LDC receives the aggregated rate of return from the pool rather than receiving many different rates of return from individual customers. This approach might allow CHP to attract new capital for residential and commercial applications with gas LDCs utilizing their lower cost of capital, possibly plus a premium.

The administrative entity could be almost any new or existing entity or agency, as long as normal protocols are followed to set up and isolate the assets and liabilities related to the investments, payment streams, and contracts. Since its obligations are secure and isolated, it is also considered a bankruptcy remote entity. There are many examples of this structure being used to finance energy assets and attract risk-averse investors in North America and Europe. The variation in this example is that the assets and customers of multiple gas LDCs are aggregated instead of those of a single company being placed into the vehicle. This may be one possible route to attract capital and fund a portfolio of CHP investments in residential and commercial applications.

[148] This may create a situation of high cost of asset recovery for equipment that also most likely has limited resale-ability, increasing the cost of customer acquisition.

Implications for gas LDCs

- For microCHP, look for ways to support research and development aimed at driving down manufacturing costs and facilitating wider distribution and installation of product.
- Support initiatives that facilitate easier, faster, and less costly ways to permit new CHP sites and drive interconnection standards towards uniformity.
- For microCHP, support common data standards, monitoring, collection and centralization from existing CHP sites for further analysis and outreach/educational programs.
- Work with regulators to expand the number of states that count CHP in Renewable or Energy Efficiency Portfolio Standards on the basis of efficiency gains.
- Work with state regulators to create equitable standby provisions, charges, and policies for CHP and help level policy playing fields for sale of power/heat/steam into wholesale and retail markets from CHP by gaining remuneration based on capacity value and voided costs of actual technologies.

CHP APPENDIX

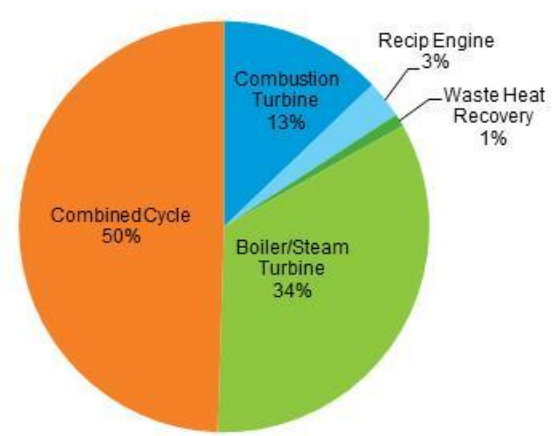
CHP Technologies

The technologies (or prime movers) used for CHP are steam turbines, reciprocating engines (internal combustion and Stirling engines), gas turbines, microturbines, and fuel cells. Two categories of CHP may be distinguished, depending on whether the primary output is steam or power. Steam turbine CHP systems are generally configured as a bottoming cycle process, producing heat or steam as the primary output, with electricity generation a byproduct. The other technologies generate electricity as their primary product, capturing waste heat from electric generation for thermal uses. A system that is configured to produce electric power, with heat as a by-product, is called a “topping cycle” CHP application. It takes the exhaust from an electric generator and uses that heat to provide space, water, or process heat or steam. Note that a topping cycle CHP unit is similar to a combined cycle gas turbine (CCGT) in that both use the exhaust from a power generator in a secondary process. The fundamental difference between the two is that the CHP unit uses the prime mover exhaust for space or process heat or steam, while the CCGT uses the turbine exhaust to generate more electric power.

Combined cycle technologies (a natural gas turbine combined with a steam generator) provide half of the total CHP capacity; although they only account for 6% of all installations due to their significantly larger plant size (see Figures IX.1 and IX.2). Reciprocating engines tend to be on the other side of the size spectrum, accounting for 51% of all installations but only 3% of capacity.

FIGURE IX.3

US CHP Capacity by Technology (81,800 MW)



Source: ICF International

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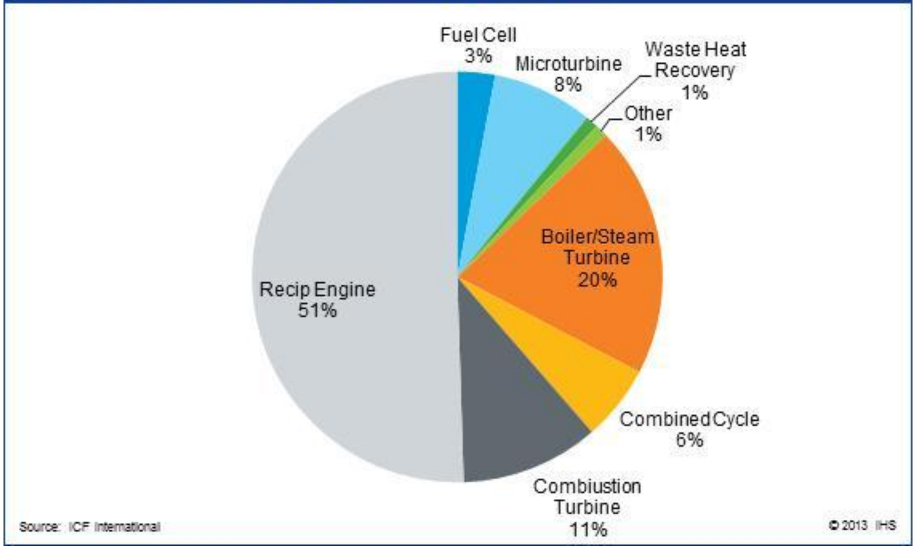
FIGURE IX.4

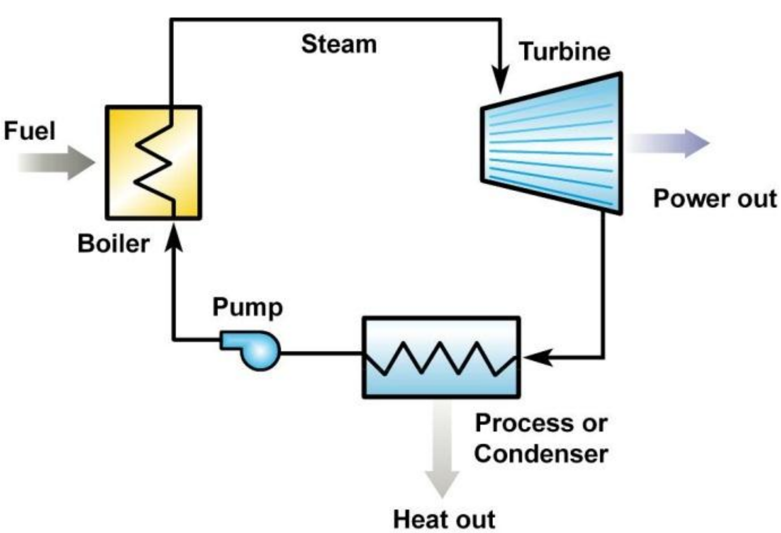
Number of US CHP Sites by Technology (4,100 sites)



- **Steam turbines** are the most common prime mover by capacity for CHP in the United States today. They range in size from 50 kW to several hundred MWs and use high pressure steam from a boiler to drive the rotary motion of the blades that produce electricity via a driven electric generator. The exhaust steam from the turbine is then delivered to the thermal application (see Figure IX.3). It is distinguished by the separation of the boiler from the power generator, enabling the use of a variety of boiler fuels to produce steam. Steam turbines accounted for 20% of CHP installations in 2012 and 34% of CHP capacity.

FIGURE IX.5

Components of a Steam Turbine System

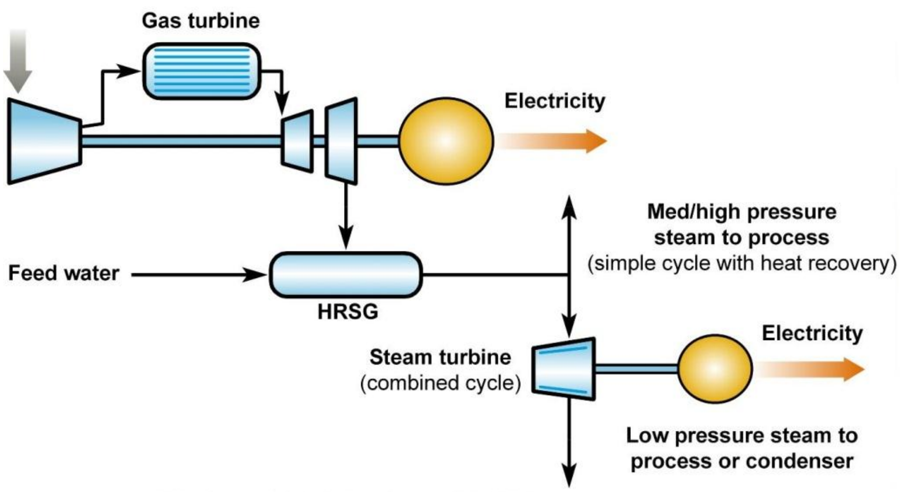


Source: US Environmental Protection Agency, IHS CERA.
30602-6

- **Gas turbines,** or combustion turbines, revolutionized airplane propulsion in the 1940s before making their way into power generation applications. They range in size from 500 kW to about 250 MW and burn natural gas or other fuels to create hot gases that drive the blades of a gas turbine to produce electricity via an electric generator. The turbine exhaust is typically fed into a heat recovery steam generator (HRSG) to produce steam, although alternatively the heat can also be used directly in other applications. The steam may be used for process heat or steam or in a combined cycle process to power a steam turbine to produce more electricity (see Figure IX.4). In 2012, combined cycle processes dominated large CHP applications, accounting for 50% of CHP capacity but only 6% of CHP installations. Combustion turbines made up 13% of CHP capacity and 11% of installations.

FIGURE IX.6

Heat Recovery from a Gas Turbine System



Source: US Environmental Protection Agency, IHS CERA.
30602-7

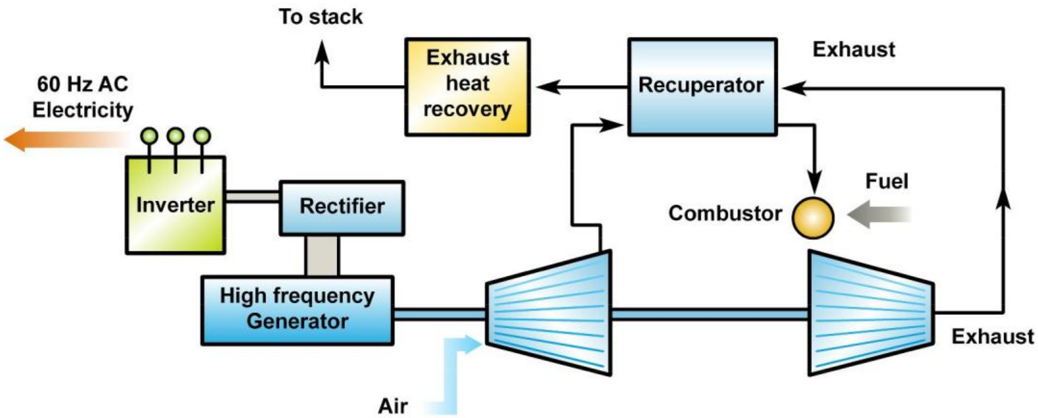
- **Reciprocating engines** are the most common CHP technology and generally range from 10 kW to 5 MW and are often used for temporary power production, e.g., back up generation. They accounted for 51% of the CHP installations as of 2012 but only 3% of total CHP capacity. Reciprocating engines include internal combustion (essentially automotive) engines that may use spark ignition or compression ignition.

  This category also includes external combustion engines such as the Stirling engine, which moves pistons by a gas that is externally heated via a heat exchanger. Stirling engines come with free pistons or with kinematic technology in which the piston is connected to the output shaft via a rod. The free piston Stirling engine has a lower electric efficiency than the kinematic Stirling but in both cases efficiency is between 12% and 20%. Several Stirling engine products are more common in the European market.

- **Microturbines** are generally up to 500 kW, operate along a rotating shaft that includes a compressor and a combustion turbine which drive an electric generator in a single or dual shaft (see Figure IX.5), and can be fueled by hydrogen, natural gas, propane or diesel. In principle they are very reliable since all the rotating components are along a shaft. High quality waste heat can also be recovered by such units. Microturbines make up about 8% of CHP installations but comprise a minuscule proportion of total CHP capacity.

FIGURE IX.7

Microturbine CHP System



Source: US Environmental Protection Agency, IHS CERA.
30602-8

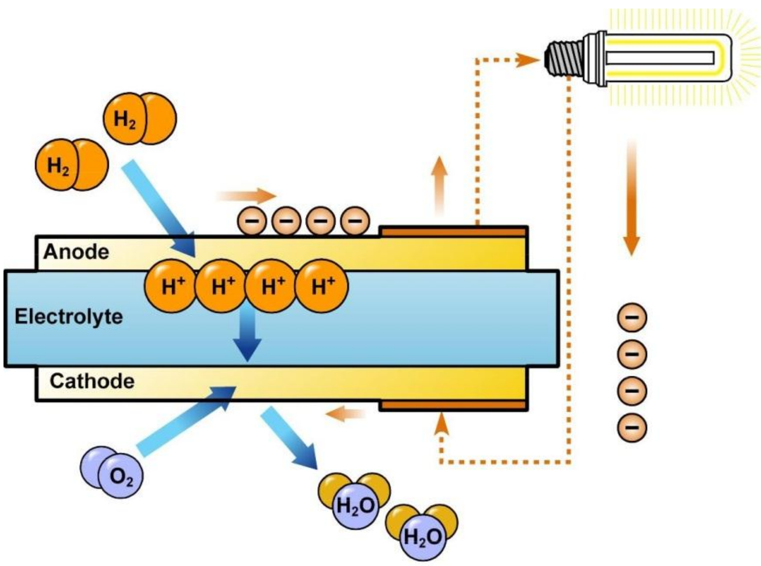
- **Fuel cells** generally fall into the 0.5 to 1,200 kW range and unlike the other CHP technologies use an electrochemical, or battery like, process rather than a mechanical process to produce electricity and heat. They use hydrogen (derived from natural gas or other hydrocarbon fuel) and oxygen (from ambient air) to produce water and electricity. For fifty years fuel cells have been used by the National Aeronautics and Space Administration space missions.

  A fuel cell consists of three parts—a cathode (positively charged electrode) into which oxygen is fed, an anode (negatively charged electrode) into which hydrogen is fed, and an electrolyte (see Figure IX.6). At the anode the hydrogen atom is ionized in the presence of a catalyst. The free electrons flow into an electrical circuit while the hydrogen ions flow through the electrolyte into the cathode where they combine electrochemically with the oxygen (again in the presence of a catalyst) to produce water.

  Fuel cells differ in the electrolyte used, the operational temperature, and the quality of heat recovery, e.g., hot water or steam. There are five types of fuel cells -- proton exchange membrane (or polymer electrolyte membrane), phosphoric acid, alkaline, molten carbonate and solid oxide.

FIGURE IX.8

Fuel Cell Electrochemical Process



Source: US Environmental Protection Agency, IHS CERA.
30602-9

The first three types are low temperature technologies and the latter two types are high temperature. The low temperature fuel cells require a reformer to break the natural gas fuel into hydrogen and carbon dioxide waste. Such a reformer has a comparable cost to the fuel cell itself and has been a difficult component to commercialize. Several low temperature products are in the market introduction phase in the United States and Japan. Numerous high temperature fuel cells have also been introduced as technology demonstrations. The key advantage of the high temperature fuel cells are their high efficiency and the capability to auto reform the fuel to obtain the required hydrogen for the fuel cell. The high cost of the high temperature fuel cells has also been a barrier for the commercialization of the technology. Nevertheless there are several high temperature fuel cell technologies on the market with electric output of 1 kW to several MW, with and without heat recovery.

Fuel cells can operate indefinitely given a continuous fuel supply. They have few moving parts but are complex and require maintenance every 5-7 years due to the effect of corrosive materials. Although fuel cells have been in development for more than 100 years and a number of models are commercially available, they have not yet gained widespread acceptance. As of 2012, fuel cells accounted for 3% of US CHP installations but accounted for a negligible proportion of CHP capacity.

Microgrids

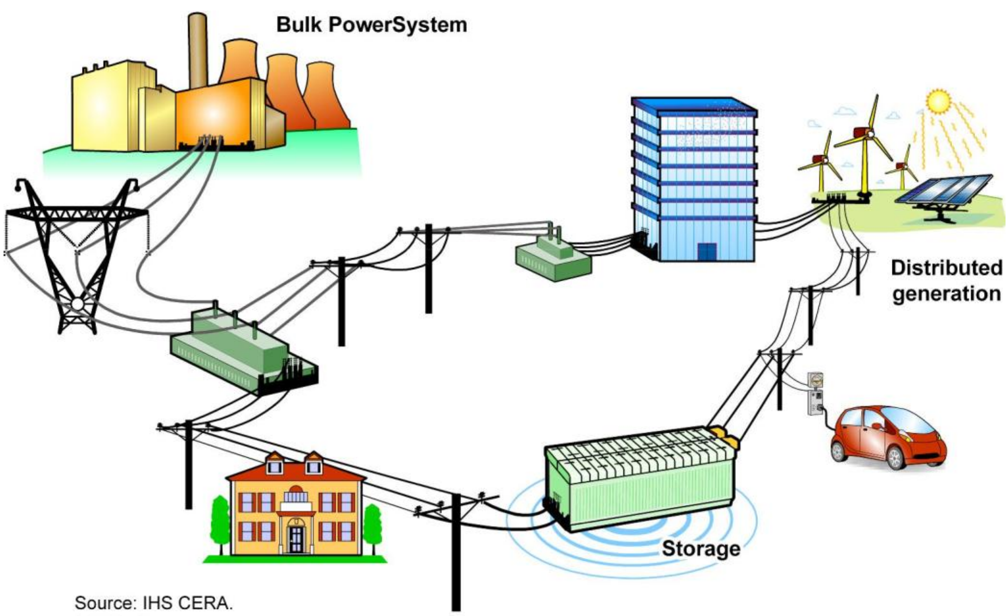
A microgrid is defined in the Energy Independence and Security Act of 2007 as an “integrated energy system consisting of interconnected loads and distributed energy resources (including generators and energy storage devices), which as an integrated system can operate in parallel with the utility grid or in an intentional islanding mode.”[149] Microgrids are considered a collection of technologies that enable the

[149] Islanding mode means disconnected from the grid.

centralized control and digital communication necessary to coordinate generation, demand, storage, direct load control, electricity distribution, and the import of electricity from the bulk power system (see Figure IX.7), regardless of the fuel source. Not just natural gas, but also wind and solar PV technologies are generating resources for microgrids. In theory, a microgrid has the capability to operate as an electric island for reliability, efficiency, economic, or environmental purposes. Some have the ability to export power to the grid.

FIGURE IX.9

Microgrid Schematic



Source: IHS CERA.
30602-10

Microgrids are most commonly used in military installations, universities, hospitals, residential neighborhoods, and office parks to mitigate power outages and protect against cyber-attacks, to integrate renewable and DG resources, and to increase efficiency by reducing fuel dependency, fuel costs, and emissions. However, the individual fuel and technology mix of the generating resource of any microgrid heavily influences any realized economic or environmental benefits.

Chapter X: Natural Gas in Transport

In Brief

- The expectation that the oil/gas price ratio will remain high for the long-term makes oil vulnerable to competition from natural gas in all transportation sector sub-segments except in aircraft and lubricants, with the greatest potential in the on-road vehicle market, which accounts for 79% of total demand for transportation fuel. The large and growing LDV market presents an opportunity for increasing natural gas demand if the challenges of high up front costs, limited maximum travel distance and a sparse refueling network can be mitigated.

- One benefit of natural gas vehicles (NGVs) is lower greenhouse gas emissions. On a well-to-wheels basis, an NGV has 17% lower emissions than a similar gasoline-powered LDV. A light-duty NGV's emissions of 0.30 kg CO_2e per mile travelled are equivalent to those of a hybrid electric car, plug-in hybrid (PHEV) and battery electric vehicle (BEV) using electricity produced from coal. NGVs also emit much less particulate matter and volatile organic compounds than gasoline and diesel cars, thereby contributing less to the formation of ozone in urban areas.

- Several thousand medium-duty vehicles (MDVs) are powered by natural gas, including school buses and delivery trucks and vans and the fleet is growing. Typical payback times for the higher initial costs are 3-5 years, depending on VMT. The more a vehicle is driven, the more quickly fuel savings accumulate.

- The economics of natural gas use in transportation are strongest for heavy-duty vehicles (HDVs)—primarily class 7 and 8 long-haul trucks using CNG or LNG. The high VMT of these vehicles enable a payback period of less than 3 years, which is viewed favorably by HDV operators considering the investment. Construction is underway on LNG refueling infrastructure and a considerable network is expected to be in place by 2015.

- Emerging uses of natural gas in transportation (marine vessels, railway locomotives) also have potential, once certain infrastructure and technology issues are resolved.

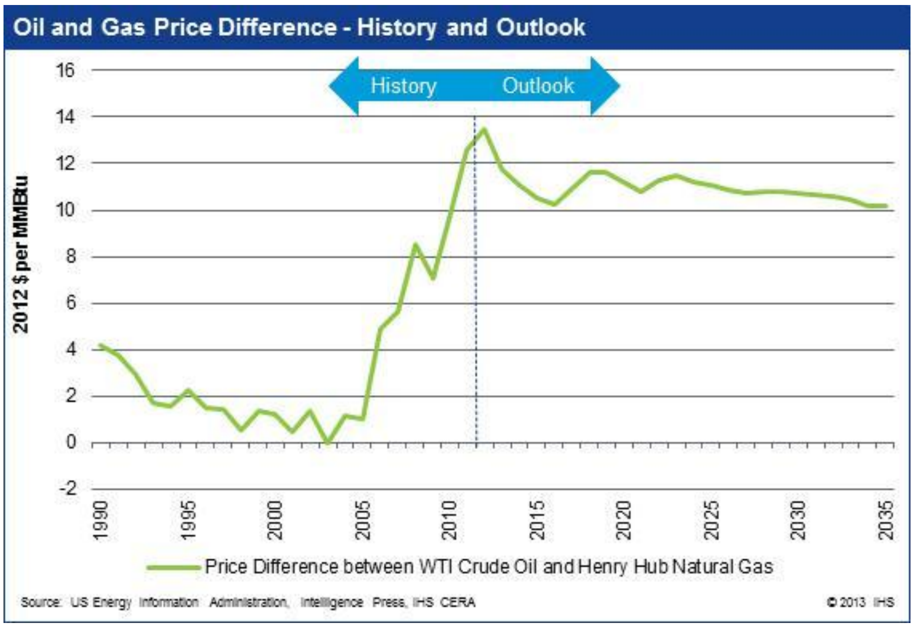
The US transportation market offers a potentially large new source of natural gas demand. Petroleum based products hold a near monopoly on transport currently, ranging from gasoline for the LDV fleet through diesel in the freight industry, jet fuel in aviation, and residual bunker fuel for marine transport. However, at a time of historically high annual average oil prices, and growing concern about the stability of the key oil producing regions of the Middle East and North Africa, there is heightened interest in alternatives to petroleum for transportation. Increased use of natural gas in transport would help address these concerns, in particular the energy security objective of reducing oil imports that has been a tenet of US national policy for many years.[150] In addition, the benefit of the lower CO_2 footprint of natural gas compared to gasoline and diesel could address potential federal policy priorities of reducing CO_2 emissions. Emissions of particulate matter and volatile organic compounds, key contributors to the formation of ozone, are also much lower for NGVs than for gasoline- or diesel-powered vehicles. Oil

[150] Currently oil imports, on a net basis, constitute about one-third of total oil demand – a reduction from its high point owing to the recession, increased efficiency of the motor fleet, and increased domestic oil production.

imports and energy security are addressed in this chapter, as is a well-to-wheels comparison of the CO_2 footprint of both natural gas and petroleum fuels.

Oil's degree of dominance in the on-road vehicle market is more vulnerable to competition from natural gas than at any other time in recent memory. The enduring wide price difference between oil and natural gas illustrated in Figure X.1 shows one of the primary drivers of conversion to natural gas fuels: simple economics.

FIGURE X.1

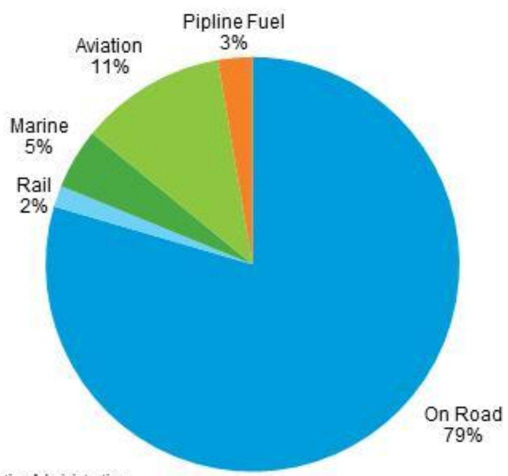


US transportation market overview

The largest segment of the overall transportation fuel market is the on-road vehicle sector, accounting for more than 79% of total demand for transportation fuel (see Figure X.2). Next is aviation with an 11% share, followed by marine transportation (5%), pipeline fuel (2%) and rail transportation (less than 2%). Except for the natural gas used as pipeline fuel, almost all transportation fuels are oil-based (see Figure X.3). In 2012, natural gas provided 2.8% of all transportation fuel in the United States, of which 2.6% was pipeline fuel and only 0.2% (47 trillion Btu – 0.1 Bcf per day) was CNG for vehicle use. The potential growth opportunities for gas in transport are therefore quite large.

FIGURE X.2

Transportation Energy Demand by Sub-Sector, 2012



Source: US Energy Information Administration

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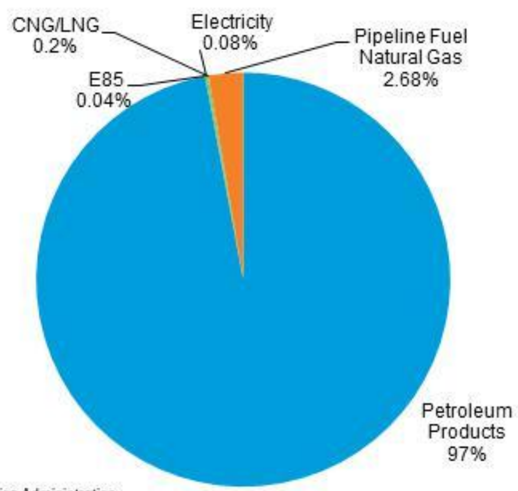
FIGURE X.3

Transportation Energy Demand by Fuel Type, 2012



Source: US Energy Information Administration

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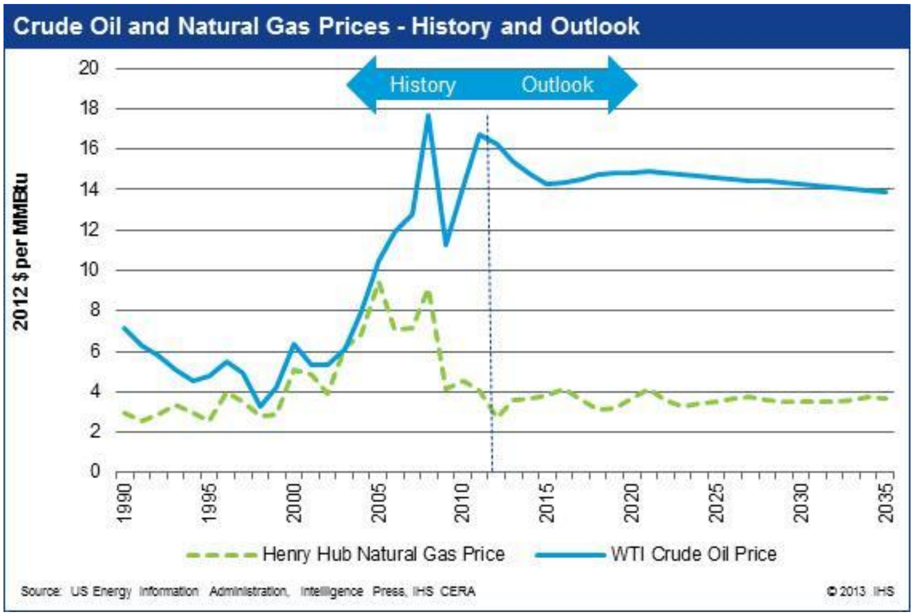
Natural gas as a vehicle fuel

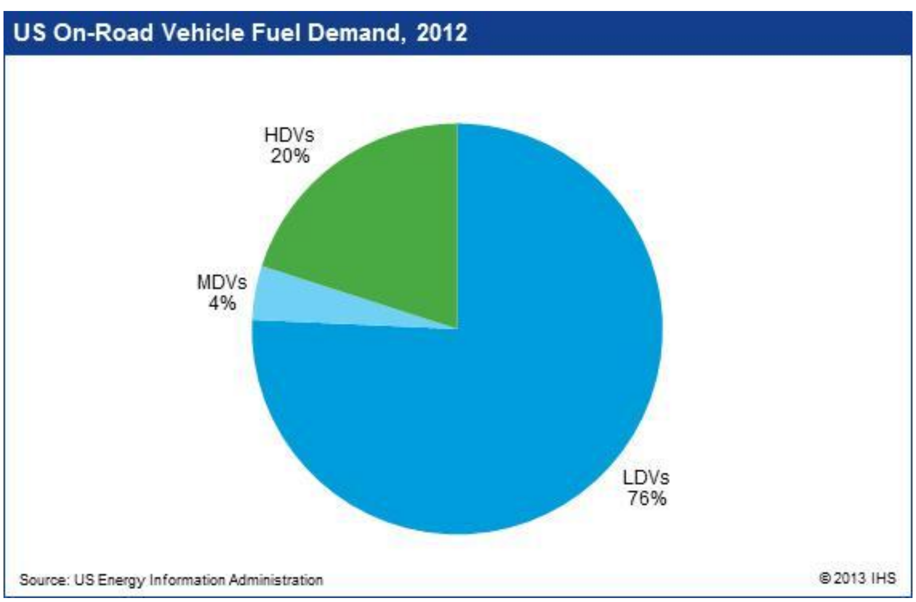
There are varying degrees of opportunity for natural gas in all transportation sub-sectors except aviation and lubricants, with the greatest potential in parts of the on-road vehicle market. While there are some challenges to natural gas penetrating this market, the wide price differential between oil and gas—which is expected to endure—provides the best opportunity for natural gas to go from a niche fuel to key contributor at least in some vehicle segments. Sustained low prices for natural gas together with continued high prices for oil give natural gas an operating cost advantage over oil in transportation as well as other uses (see Figure X.4). The political environment is also favorable, with increasing consensus on the benefits of a growing domestic energy supply base.

FIGURE X.4



On-road transportation is generally divided into 3 sub-markets—light-duty vehicles, medium-duty vehicles, and heavy-duty vehicles. LDVs include passenger cars and light trucks, whereas MDVs and HDVs are usually fleet and commercial vehicles and often travel greater distances. The LDV fleet accounts for over 75% of total US vehicle fuel demand, MDVs for less than 5%, and HDVs for about 20% (see Figure X.5). The opportunities and challenges to increasing the share of natural gas in on road vehicles vary between the LDV, MDV, and HDV market. Overall, IHS CERA expects the greatest natural gas demand growth to occur in the HDV and MDV markets, due to market and cost dynamics that are discussed later in this chapter. However, IHS CERA also sees potential for natural gas to increase its share in LDVs in the coming decades—especially LDV fleets.

FIGURE X.5



Natural gas in on-road vehicles can be used as either CNG or LNG depending on the application and cost dynamics (see the box "Natural gas: compressed and liquefied"). Although natural gas can also enter the transportation market indirectly through the generation of electricity for plug-in electric vehicles, this section focuses only on natural gas used directly as CNG or LNG on board the vehicle.

Natural gas: compressed and liquefied

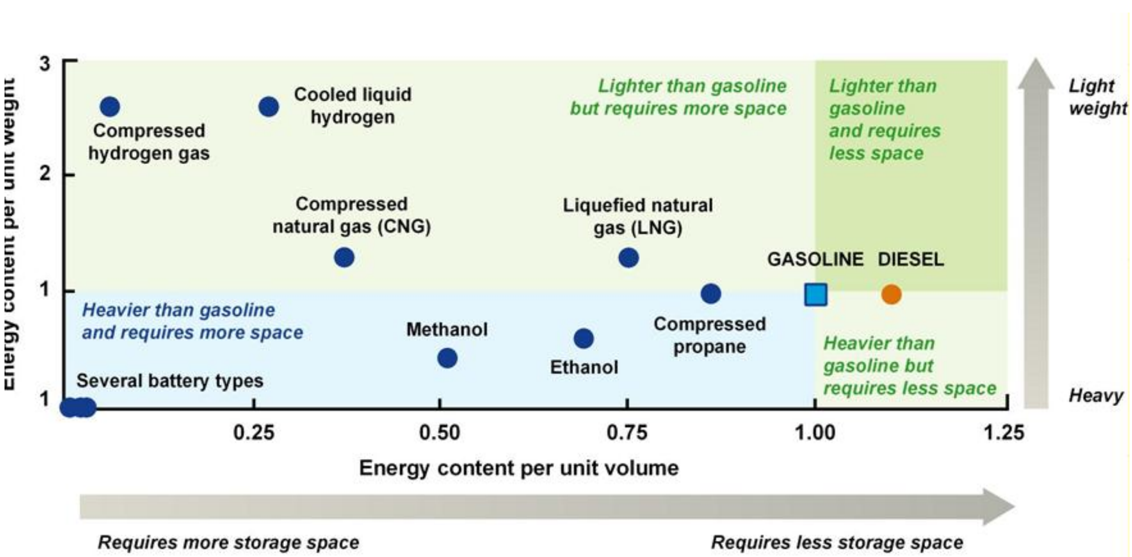
Natural gas is almost pure methane (CH_4). It is primarily used for space and water heating, industrial processes, and power generation. Its use in transportation has been limited by its low energy density and lack of refueling infrastructure.

Natural gas has an energy density of 0.364 megajoules (MJ) per liter while gasoline's energy density is almost 100 times greater at 32.1 MJ per liter. Therefore for vehicle use, natural gas must be compressed or liquefied to increase its density and provide adequate range compared to gasoline. Compressed natural gas is natural gas that is compressed to roughly 2,500– 4,000 pounds per square inch, giving it an energy density of 9.3 MJ per liter (see Figure X.6). Compression allows more energy to be contained in a relatively small tank providing an acceptable range of driving for a conventional motor vehicle. Assuming a conventional fuel tank size, CNG provides about half of the range of a conventional gasoline vehicle. CNG is primarily used in LDVs and inner city medium-duty trucks such as delivery trucks, buses, and municipal vehicles.

Alternatively, natural gas can also be liquefied by reducing its temperature to -260° F (-160° C). This reduces its volume by a factor of 600, allowing it to be transported on ships or used to fuel heavy-duty trucks. Liquefied natural gas is generally referred to as LNG.

FIGURE X.6

Energy Density Comparison of Several Transportation Fuels (indexed gasoline = 1)



IHS CERA reproduced based on US EIA, "Few transportation fuels surpass the energy densities of gasoline and diesel", *Today in Energy*, February 14, 2013.
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Light-duty vehicles

Natural gas in LDVs is stored on the vehicle as CNG. Until recently the only factory installed available CNG passenger vehicle model on the US market was the CNG Honda Civic, which has been in production since 1998. Ford has also recently announced that it will offer a CNG version of the F150 starting in 2014. This will be the first half-ton pick-up on the market. However, more automotive companies are considering offering CNG vehicles and are focusing their R&D efforts on improving the existing engine technology. Unlike battery technology for electric vehicles, automotive companies view CNG technology as a mature technology that is able to ramp up as demand builds. Therefore, the main challenges to increasing natural gas in the LDV market are less on the vehicle technology side, and more on the infrastructure side (such as the creating a network of CNG refueling sites) and in creating consumer acceptance of natural gas as a fuel that, in turn, translates into demand for natural gas-powered vehicles.

NGV LDV challenges and pathways forward

Vehicle technologies and products within the LDV market need to compete on a wide range of parameters to gain market acceptance. Consumers purchase vehicles based on many factors, with cost, convenience, and the environmental footprint of the vehicle being a just few of the parameters. Therefore, any new vehicle, whether it is a new conventional vehicle model or new vehicle/engine/powertrain technology, needs to compete on all these fronts to gain any significant market share. At the same time, vehicles based on a new technology or fuel, such as a CNG vehicle, may face additional challenges as these vehicles often require consumers to modify their behavior or views on mobility. For example, CNG vehicles offer the opportunity for home refueling, which is different from gasoline or diesel vehicles, changing how consumers think about the availability of refueling infrastructure.

When looking at the potential for natural gas-fueled LDVs IHS CERA sees consumer, industry, and policy challenges to NGV adoption but also opportunities to overcome these barriers. These challenges are:

Consumer challenges:

- CNG LDVs' up front costs are currently higher than those of an equivalent gasoline vehicle
- There is currently a limited NGV product offering
- Natural gas vehicles have a more limited range than gasoline powered internal combustion engine (ICE) vehicles
- There are currently a limited number of commercial CNG refueling stations
- CNG vehicles take longer to refill than conventional gasoline and diesel vehicles
- CNG vehicles have an uncertain residual value

Vehicle industry challenges:

- Lack of consumer awareness
- Limited policy support for CNG vehicles

- Limited original equipment manufacturer (OEM) supplier base for CNG components, which keeps costs high
- Retail fuel suppliers are generally small independent business owners making it difficult to coordinate the expansion of costly CNG refueling infrastructure

Policy challenges:

- Government policy and incentives are currently not seen as allowing a level playing field, but rather seen as favoring other alternative vehicles and fuels above NGVs.
- Automotive and fuel supplier companies have worked with regulators to develop very specific fuel quality standards for traditional motor fuels. Natural gas fuel specifications also need to be clearly defined in terms of trace containments content, moisture, sulfur, etc.

Consumer challenges facing NGV adoption in the LDV market

Ultimately the success of NGVs in the LDV market depends on consumer demand which is highly influenced by vehicle purchase price. Today, natural gas LDVs have a higher purchase price than a similar gasoline-fueled automobile (see Table X.1). Additionally, CNG engine retrofits can cost between $4,000 and $5,000 more than their equivalent gasoline ICE passenger vehicle, and CNG retrofits for larger trucks can cost up to $15,000. For example, the Ford F150 CNG truck can cost an additional $7,500-$9,500 depending on the fuel tank capacity. While the cost differential may decrease over time if production volumes increase, this is a barrier to increasing demand today.

TABLE X.1

Cost and Performance Attributes of Natural Gas and Gasoline Vehicles

	Gasoline	NGV
Sticker Price	$21,000	$25,500
Gasoline-equivalent fuel economy (mpg)	30	31
Fuel price ($ per gallon gasoline-equivalent)	$3.50	$2.10
Driving range between refueling (miles)	300-400	170
Home refueling infrastructure cost	N/A	$5,000
Time required for home refueling	N/A	6-8 hours
Commercial refueling infrastructure	162,000 stations	1,218 stations
Commercial refueling infrastructure costs	N/A	$500,000 - $750,000
Time required for commercial refueling	Few minutes	Few minutes

Source: IHS CERA

Note: For conventional gasoline and diesel, commercial refueling infrastructure costs can be considered to be zero since the stations are already built.

However, with natural gas prices being below gasoline prices—and expected to stay there— operating costs for CNG vehicles are lower than for gasoline vehicles. Therefore, the higher CNG up front vehicle cost can be paid back over time through lower fuel costs. IHS CERA estimates that given the assumptions in Table X.1 of a comparable ICE gasoline vehicle, a consumer can pay back the additional up front $4,500 CNG vehicle cost within five years at a CNG retail price below $1.80 per gasoline gallon equivalent (gge). However, the fuel savings calculation is very sensitive to the number of miles traveled, the assumed gasoline price, the assumptions around vehicle tax credits, and the payback period. For example, if the same tax credit of $7,500 now given to electric vehicles were extended to NGVs, a consumer could pay up to $6 per gge for CNG (higher than today's price) over five years and be cost neutral compared to a comparable ICE gasoline vehicle, making the economics of NGVs much more favorable. Today CNG retail prices are in the range of $2-$3 per gge. Even without the vehicle tax credit, there are cases where motorists who drive a higher-than-average number of miles each year, like fleet vehicle operators, would see the higher CNG vehicle purchase price paid back in less than three years. As one example, if a five-year payback period is acceptable to consumers and assuming a CNG price of $2.10 per gge, IHS CERA estimates that an NGV would be cost-effective if gasoline prices were around $4 per gallon.

Fleet vehicles, such as taxis, are typically driven more intensively than the average consumer vehicle. In addition, fleet vehicles often have relatively fixed driving ranges and the opportunity for central fueling locations. These factors make it easier to justify and pay back the higher up front CNG vehicle cost.

While up front NGV costs are higher than those for gasoline vehicles, there is still opportunity to see this cost differential reduced. Today, NGVs and their associated supply chain components do not benefit from the economies of scale gained through large scale production volumes. If NGV sales were to increase, it is expected that the capital cost differential between NGVs and conventional vehicles would shrink as these production economies were realized.

Another option to lower the cost differential between NGVs and gasoline vehicles is through vehicle tax credits. As discussed above, the federal government offers a tax credit of up to $7,500 for electric vehicle purchases, with additional credits available at the state level. No tax credits are currently available for NGVs, although one was proposed in the 2011 Natural Gas Act for NGVs. Advocates for alternative fuels and vehicles such as NGVs often point out that federal and state vehicle tax credits should be available for all types of alternative vehicles and fuels and that government should let the market decide which pathway it wants to go.

Driving range limitation has also traditionally been a challenge. CNG's lower fuel density limits the driving range of an NGV between refueling stops compared to a gasoline vehicle with the same fuel tank size. For example, the CNG Honda Civic has a range of 170 miles while the gasoline version has a driving range between 300-400 miles (see Table X.1). However the issue of range can be overcome by design changes. Automotive companies can add additional CNG tanks to provide greater range or they can design dual fueled vehicles – vehicles that can run on both gasoline and CNG through two fueling systems. For example, the Ford F150 can achieve 750 miles on one tank of natural gas. Of course, additional tanks, larger tank size, or dual fuel systems will increase the associated cost of the vehicle.

Refueling the light-duty NGV

The current lack of CNG refueling infrastructure compounds the range anxiety associated with NGVs. There are approximately 1,200 CNG refueling stations in the United States according to DOE, of which only 566 are open to the public. This compares to about 160,000 retail gasoline stations. With a two-hose commercial CNG station costing between $500,000 and $750,000, fuel retailers have been reluctant to invest until consumer enthusiasm for NGVs becomes evident. At the same time, consumers are reluctant to purchase NGVs in part because of the limited number of refueling stations – a classic chicken-egg situation.

However, while CNG commercial retail stations servicing the LDV fleet may take time to develop, LNG commercial stations targeting medium and heavy-duty vehicles are being built across the United States (as discussed further below). Therefore, in the future, new LNG stations could potentially be designed to deliver CNG as well. Such planning might help provide a bridge to developing a CNG transcontinental network.

Additionally, as the economics of natural gas vehicles become more attractive, innovative refueling solutions are likely to be introduced to the market. For example, General Electric (GE) Ecoimagination and Peake Fuel Solutions, an affiliate of Chesapeake Energy Corporation, have developed “GE CNG in a Box”, which is a fully integrated stand-alone unit that connects to natural gas distribution lines. It is expected to be available for fleets as well as commercial fueling stations seeking to offer CNG fuel.

Home refueling systems for LDVs are also available. The CNG refilling unit called the Phill, produced by BRC FuelMaker, is the most well-known. These units cost $5,000-$7,000 and can refill an NGV in 6-10 hours depending on the capacity of the tank and the compression and dispensing rates. While filling the fuel tank at home is a convenience, the 6-10 hour refill time is a likely detriment. (In contrast, a commercial refueling unit has a fill time similar to that of a gasoline pump—about 5-7 minutes.)

The hurdles standing in the way of increased CNG vehicle popularity are not necessarily the same for every consumer, which provides some opportunity to the industry—especially with today’s wide oil-gas price differential. For example, the average US driver drives less than 40 miles per day. Today’s NGVs offer enough range to exceed the daily needs of a typical driver, so for those motorists who principally use their vehicle in a set pattern- such as a commute- the range issue may be neglible. Additionally NGVs offer the convenience of filling up at home, something that gasoline or diesel vehicles cannot offer. While filling up a CNG vehicle at home can take between 6 and 10 hours, this is also based on an empty tank. Consumers can chose to fill up for less time each day or fill up at home every few days when it is convenient for them.

Industry challenges facing NGV adoption in the LDV market

From industry’s standpoint, there are two key challenges: better consumer education about the benefits of NGVs and finding solutions to the refueling network problem.

Currently there is a lack of consumer awareness and knowledge about the availability and benefits of NGVs. Increasing consumer awareness is therefore critical to increasing natural gas’ penetration of the LDV market. This information exists through industry, associations, and government websites, but it is still missing the majority of consumers. Instead, vehicle technology and fuel options are currently advertised through the automotive manufacturer at a model or brand level. This style of communication makes it more difficult to educate consumers more broadly on the benefits of natural gas vehicles.

One solution could be a consortium of organizations and companies who work together to educate the public on the benefits of NGVs specifically and why consumers should buy them. Whether this is done by the government or by the private sector or in combination still needs to be determined.

Expanding the CNG commercial refueling station is also clearly critical to NGV adoption. Though the cost to invest in a refueling station is an issue, an additional challenge is that the majority of retail fuel suppliers are small independent business owners. This makes it difficult to coordinate any type of CNG retail expansion. It also typically makes the current cost of installing CNG prohibitive. Two critical issues need to be addressed to increase the number of refueling stations. First, the high cost of CNG infrastructure needs to be reduced, whether through new business models or technology development. Second, better coordination is needed across the large number of retail station stakeholders. These business owners need to be educated on the benefits of adding CNG pumps and need to work with urban planners on the required density of CNG pumps that are needed to gain consumer acceptance. Both these issues are critical to expanding the CNG refueling network and increasing NGV demand.

Transportation fuel specifications for natural gas

ICEs require detailed motor fuel specifications for moisture content, sulfur, trace containments, among other parameters. As with any transportation fuel, natural gas will need to meet a defined set of fuel specifications. This is something that fuel suppliers, automotive companies, and government agencies will need to coordinate.

For example, pipeline gas often needs to be "dried" to reduce its moisture content and often filtered for contaminants. There is also the question of sulfur content. Currently US gasoline must contain no more than 15 parts per million (ppm) of sulfur. Sulfur levels higher than this can damage the exhaust after-treatment systems onboard the vehicle. Natural gas with a sulfur content of greater than 15 ppm may not affect dedicated CNG vehicles using different after-treatment systems. However, higher sulfur natural gas may be damaging for dual-fuel vehicles that alternate between natural gas and gasoline. CNG retail outlets are expected to offer just one type of natural gas, and therefore it is important to assess the appropriate levels of sulfur in CNG. Research is currently being coordinated between the American Gas Association and the Coordinating Research Council (CRC) to support a national survey of natural gas fuel quality from the perspective of a motor fuel. Sulfur is among a number of components of CNG that is being tested as part of this work.

Policy challenges facing NGV adoption in the LDV market

Perhaps the greatest policy challenge holding back NGVs is the lack of an even playing field in terms of federal government incentives.

Federal fuel, infrastructure, and vehicle tax credits typically favor other vehicles and fuels over NGVs. For example, electric vehicles benefit from a $7,500 federal vehicle tax credit, while there are no federal tax credits available for NGVs. Also, President Obama has a policy goal to have one million electric vehicles on the road by 2015. Until end 2012, ethanol blenders received a $0.45 per gallon federal tax credit and ethanol still benefits from the RFS which mandates annual levels of biofuel blending. Today, natural gas receives some tax credit benefits but there is still not a level program of incentives across the different alterative vehicle technologies, fuels, and infrastructure.

A powerful policy lever that influences the types of vehicles automotive companies produce is the Federal Corporate Average Fuel Economy Standards, or the CAFE standards. These standards provide incentive multipliers for alternative fuel vehicles. These multipliers are an important means by which the government can support greater deployment of alternative fuel vehicles. Unlike tax credits, fuel economy multipliers are revenue neutral to the government and accordingly tend to persist more dependably over time. Because of this, vehicle manufacturers are more likely to be influenced in their product planning by incentive multipliers embedded in the fuel economy compliance framework than by policy instruments such as tax incentives, manufacturing grants, or loan guarantees.

In light of these considerations, it is important that policy makers recognize that incentive multipliers can skew the playing field if applied to some but not all alternative fuel vehicles, sometimes with unintended consequences. Incentive multipliers can be based upon performance metrics such as greenhouse gas reductions, petroleum displacement, and reductions in pollutants harmful to human health.

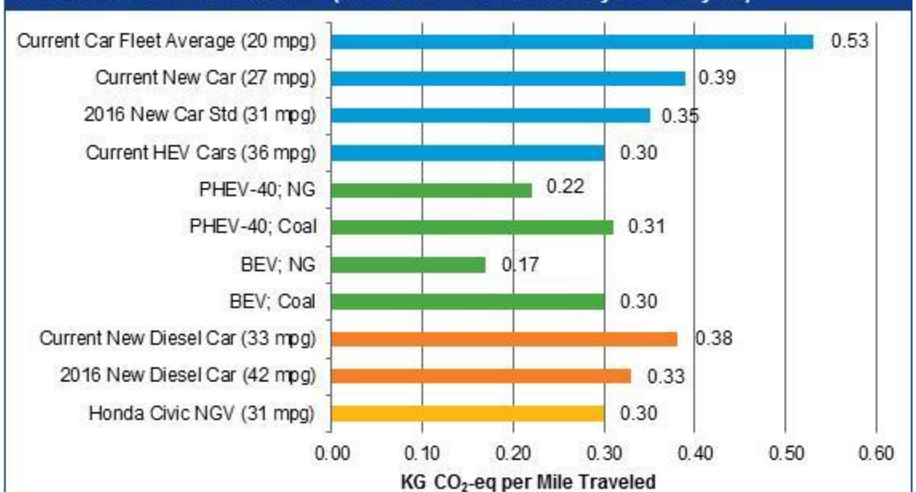
Well-to-wheels greenhouse gas emissions of light-duty vehicles

Although today's CAFE and EPA new vehicle GHG standards apply only to tailpipe emissions, a complete well-to-wheels (WTW) emissions analysis gives a more accurate measure of the contribution of various automotive technologies to atmospheric greenhouse gases and reveals a major benefit of NGVs compared to today's ICE gasoline vehicles. The WTW analysis accounts for the emissions generated in producing, processing, delivering, and combusting the fuels and electric power used in vehicles. For example, although BEVs have no tailpipe emissions, a WTW analysis captures the emissions associated with the production of electricity that BEVs consume. Depending on the CO_2 footprint of the generating technology, the BEV CO_2 footprint can vary substantially, although most of the charging of BEVs is expected to occur during off-peak hours.

Figure X.7 compares vehicle WTW GHG emissions for a variety of gasoline, electric, and NGVs expressed in kilograms of CO2-equivalent (CO2e) per mile traveled. By this measure, NGVs' emissions—at 0.30 Kg CO2e per mile traveled—are almost 20% lower than those of today's ICE gasoline vehicle. Of the technologies shown in Figure X.7 only a PHEV or BEV using electricity produced from natural gas have lower emissions than an NGV. (It should be noted that the vehicles compared are not necessarily the same size and also the electric vehicles have a number of other efficiency enhancing design features unrelated to the electric drive train that are not present in the traditional or NGV vehicles.) An electric vehicle using only electricity generated from emissions-free sources, such as renewables and nuclear power, would have near-zero emissions. A gasoline-powered automobile with a fuel efficiency equivalent to that of the NGV (31 miles per gallon) would have WTW emissions of 0.35 Kg per mile traveled—17% higher than the NGV.

FIGURE X.7

US Vehicle GHG Emissions (Wells-to-Wheels Life-Cycle Analysis)



Note: PHEV is plug-in electric vehicle, BEV is a pure battery electric vehicle, NGV is natural gas vehicle, and HEV is hybrid electric vehicle.

Source: IHS CERA

Below are some important notes to fully understand the analysis presented in Figure X.7:

- All WTW calculations use EPA fuel economy test results that have been adjusted downward by 80% to reflect real world fuel consumption and GHG emissions. "Current fuel economy" refers to 2011 sales and fleet data. The 2016 CAFE new car sales average fleet fuel economy is 37.8 mpg which translates to an on road vehicle fuel economy of approximately 31 mpg. PHEVs are assumed to travel 67% of the time on electricity achieving an efficiency of 0.364 kWh per mile and 33% of the time on gasoline achieving a gasoline hybrid fuel economy of 35 mpg. This analysis assumes a total average driving distance of 13,200 miles per year.

- The automotive models used in the analysis are MY2013 Chevy Volt, MY2013 Nissan Leaf, 2013 Fleet Average, 2013 Average New Car, 2013 Average HEV Cars, and 2013 NGV Honda Civic.
- This analysis assumes power plant efficiencies of 8,300 BTU per kWh for a new supercritical pulverized coal unit, and 7,000 BTU per kWh for a new natural gas fired combined cycle plant.
- A gallon of gasoline contains 19.4 pounds of CO_2 per gallon. NGV fuel economy is in units of gallons of gasoline equivalent. Gasoline is assumed to be 90% gasoline and 10% ethanol. GHG emissions for ethanol are based on California's Low Carbon Fuel Standard.
- Upstream GHG emissions related to gasoline and diesel are based on the NETL/DOE study *Development of Baseline Data and Analysis of Life Cycle Greenhouse Gas Emissions of Petroleum-Based Fuels*, November 2008.
- Upstream GHG emissions associated with natural gas production include upstream and midstream CO_2 emissions from the direct burning of fossil fuels for gas production, processing, storage, and transportation. Natural gas GHG emissions from upstream operations also include methane emissions that are vented or flared. These values have been adjusted from EPA estimates based on IHS CERA’s analysis in *Mismeasuring Methane: Greenhouse Gas Emissions from Shale Gas*.

Medium-duty vehicles

For purposes of this report, MDVs are defined as Class 3 through 6 trucks, with gross vehicle weight ratings between 10,000 and 26,000 pounds. There are roughly 4 million MDVs in the United States, with Class 6 vehicles (the heaviest in the MDV class) comprising almost 80 percent of them. The MDV fleet is also expected to grow over the long term, roughly at the pace of economic growth. Examples of the types of vehicles found in each vehicle class are given in Table X.2. These vehicles are used for a broad set of applications, including construction, agriculture, retail, school buses, waste management, utilities, and wholesaling (see Figure X.8).

Parts of the MDV market are a natural fit for natural gas fueling since many MDVs travel in a defined, short-range and consistent route. The *2002 Vehicle Inventory and Use Survey* of the US Census Bureau found that 60 percent of MDVs traveled within 50 miles of their home base.[151] The same survey also found that 70 percent of MDVs fuel at public gas stations or truck stops. Therefore, although MDVs do not need a large natural gas infrastructure, they clearly face some of the same infrastructure hurdles as other vehicle segments looking to convert to natural gas. An expansion of public-access CNG infrastructure is therefore key for the gas market to open up further to MDVs. As inner city commercial fleets—such as those of UPS, FedEx, AT&T, and Verizon—expand the number of CNG-powered trucks and vans, the market for fueling locations is likely to increase.

Key examples of the MDV fleet that are currently natural gas-powered are school buses, delivery trucks, and airport shuttle buses. More than 3,000 school buses and about 15-17,000 medium-duty vehicles, such

[151] US Census Bureau.

as airport shuttles and a wide variety of work applications, are powered by natural gas according to the Natural Gas Vehicle Coalition.

TABLE X.2

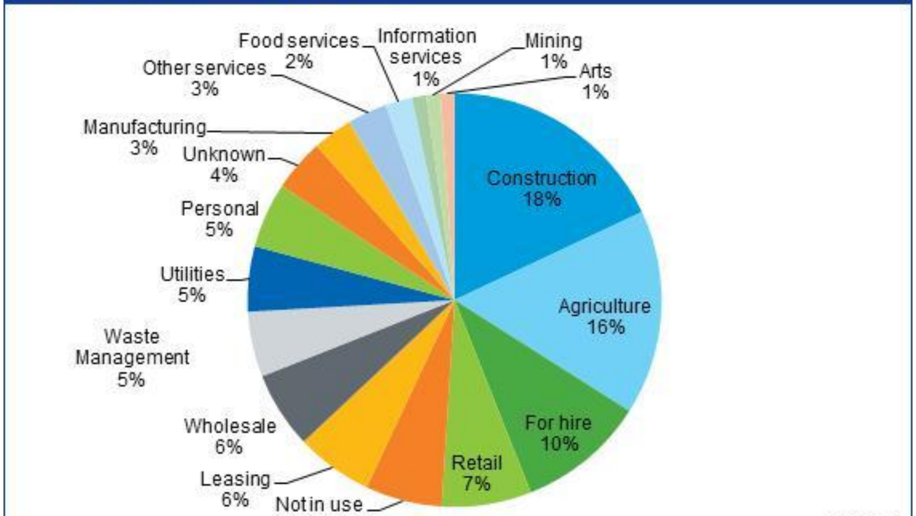
Medium-Duty Vehicle Classification

Vehicle Class	Gross Vehicle Weight Rating	Typical Application
Class 3	10,001 - 14,000 lbs	Small dump trucks, large walk in van, conventional van, city delivery truck
Class 4	14,001 - 16,000 lbs	Small delivery trucks, mini buses
Class 5	16,001 - 19,500 lbs	Bucket trucks, large walk-in vans, city delivery truck
Class 6	19,501 - 26,000 lbs	Schoo bus, rack truck, beverage truck, single-axis van

Source: US Census Bureau, IHS CERA

FIGURE X.8

Medium-Duty Vehicles by Industry



Source: IHS CERA

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Compared to heavy-duty vehicles, MDVs represent a smaller opportunity for incremental natural gas demand because these vehicles are typically driven much less than HDVs. Whereas Class 8b long-haul trucks typically travel 75,000 to 200,000 miles per year, the range of travel for Class 3-6 vehicles is typically from 15,000 to 75,000 miles. It is this difference in VMT that makes the fuel savings of switching to natural gas greater for HDVs than for MDVs, as discussed in the next section.

According to the National Petroleum Council,[152] CNG trucks cost an incremental $13,000 to $22,000 compared to a conventional, equivalent-sized truck. Although this differential could decline over time, it may take the owner of a typical MDV that is driven an average 33,500 miles per year 3-5 years to recoup the investment. Of course the payback is highly dependent on VMT. For example, if VMT were only

[152] National Petroleum Council, *Advancing Technology for America's Transportation Future*, 2012.

15,000 miles per year the payback time would increase to 6-11 years.

Heavy-duty vehicles

Heavy-duty trucks—defined as classes 7 and 8—are large, heavy and consume large amounts of fuel per vehicle. Because of their heavy loads, they require the higher horsepower provided by diesel as opposed to gasoline. Heavy-duty vehicles consumed the equivalent of 10.7 Bcf per day of natural gas in 2012. Fuel costs are the largest portion of a heavy-duty truck fleet's costs, and any ability to diminish those costs goes a long way to increasing profitability. Substituting lower-cost LNG for higher-priced diesel offers a mechanism to lower costs considerably.[153] Even though a new LNG Class-8 truck can cost $40,000–$100,000 more than a conventional diesel-powered version, the price differential between LNG and diesel is currently large enough that this up front cost can be recovered in fuel cost savings in less than three years.

Natural gas engines offer a great example of technology running ahead of demand. Until a few years ago, LNG engines were not considered viable because of a lower torque profile. A handful of companies worked through that problem and now offer high-horsepower engines that deliver the same torque with the same equivalent mileage (about six miles per diesel gallon-equivalent).

Natural gas fuel systems come in three flavors

There are three main options for using natural gas in HDVs: Compression Ignition (CI), Spark Ignition (SI) and fuel-blending (FB). A joint venture between Westport and Cummings now leads the pack, having already commercialized 12- and 15-liter high pressure direct injection (HPDI) engines, and is about to commercialize a 12-L spark ignited engine.

Natural gas substitution in HDVs has traditionally focused on "downstream" solutions, meaning that the natural gas is introduced directly into the engine through the fuel injectors. But even this comes in two varieties-an HDV LNG engine could use either the CI or SI platform. Natural gas can also be introduced "upstream", that is, in the fuel line before the fuel injectors.

Compression injection (CI): Natural gas requires a higher ignition temperature than diesel. To aid in ignition, a small amount of diesel fuel is injected into the engine cylinder along with the primary fuel - natural gas. The diesel acts as a pilot, rapidly igniting the hot combustion products, and thus the natural gas. HPDI replaces approximately 95% of the diesel fuel (by energy) with natural gas. In this case both LNG and diesel tanks are needed.

Spark ignition (SI): Spark ignition engines operate similarly to gasoline engines. The natural gas is injected directly into the engine and is ignited by a spark from a spark plug. Because no diesel is used, the engine can run 100% on natural gas.

[153] Because of its lower energy density compressed natural gas (CNG) is not an attractive substitute for diesel in this market. CNG's low energy density requires too much space and additional weight for the distances that long-haul trucks travel.

Fuel-blending (FB): Natural gas can also be introduced “upstream”, that is, in the fuel line before the fuel injectors. The natural gas/diesel composition delivered to the engine is computer controlled to generate the same power and temperature and to maintain emission profiles. This method requires no changes to the engine or injectors, but can achieve much lower displacement, typically up to 65-80%. However, as the engines can also run 100% on diesel, there is no “range anxiety.” All parts are “off the shelf” requiring no specialized manufacturing. These retrofits are not yet approved in the United States for vehicles less than two years old, however, severely limiting the market potential in the transportation sector.

Both SI and CI systems require direct injection with specialized injectors that can be quite costly. Maintenance on the systems is anticipated to be lower than on diesel engines, however, because of the lower soot emissions.

The two main economic differences between the three natural gas fuel systems are:

Up front incremental vehicle cost. The incremental cost of a new CI HDV is currently approximately $75,000 more than for a diesel truck, whereas the incremental cost of an LNG SI HDV is approximately $40,000. The LNG SI HDV is less expensive because it avoids the costly diesel emissions control technology and has a less costly fuel injection system.[154] The FB system is considerably cheaper (generally $30,000 or less) because there are no modifications to the engine or the injectors.

Engine efficiency (i.e., fuel economy). The LNG/diesel compression engine is approximately 10–15% more efficient than the LNG SI engine. This translates to better fuel economy and a faster fuel savings rate in the LNG/diesel compression engine. The upstream retrofit option is as efficient as a dedicated diesel engine, but displaces less diesel fuel than CI and SI engines, requiring more diesel fuel and leading to higher fuel costs.

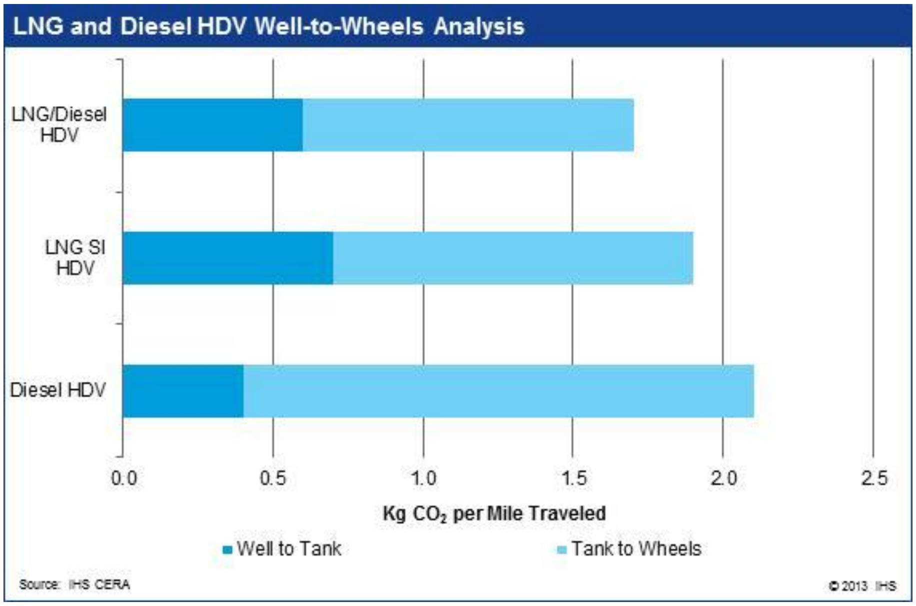
As usual, the choice between fuel systems is a trade-off between up front capital costs and operational costs. The system with the highest operating efficiency is the highest in terms of capital costs, and the system with the lowest up front costs has the lowest efficiency. Ultimately, the decision to switch and the choice of technology will depend on the fleet operator’s cash flow and the fleet’s operating characteristics.

Well-to-wheels greenhouse gas emissions of heavy-duty vehicles

Although natural gas has a 28% smaller CO_2 footprint than diesel on a tailpipe emissions basis, on a full WTW analysis this difference drops to 7-15%, depending on whether a compression or an SI engine is used. On a WTW basis, diesel trucks emit 2.08 kg CO_2 per mile while LNG trucks emit 1.77-1.93 kg (see Figure X.9).

[154] A selective catalytic reduction (SRC) system and a diesel particulate filter (DPF) are both needed to meet US Environmental Protection Agency air quality regulations for diesel emissions.

FIGURE X.9



However, one important GHG emissions source that is not included in this analysis is the potential venting of almost pure methane from LNG truck tanks. Methane has almost 25 times the global warming potential of CO_2 over a hundred-year time frame. For natural gas to stay liquid it needs to be kept below-260°F (-160°C). As the LNG tank warms, the liquid starts to turn into gas in the tank. When the tank pressure rises to a critical limit, the methane gas is vented to the atmosphere through a pressure relief valve. Depending on the ambient conditions, the age of the tank, and how much the truck is being used, an LNG truck could vent a significant amount of methane into the atmosphere in just a few days. However, LNG trucks that are used regularly, maintained, and refilled periodically should not have significant venting issues.

Overcoming challenges to LNG use in heavy-duty vehicles

Although the economics are favorable for wider use of LNG in long-distance trucking, a number of constraints and challenges must be overcome for LNG to compete fully for this market. These challenges are similar to those in the light-duty sector.

Consumer challenges:

- LNG engines: There is a limited LNG product offering.
- LNG engine costs: The up front capital costs are currently higher than an equivalent diesel truck.
- Tank weight: Cryogenic tanks are heavier than diesel tanks, which could restrict payload.

Industry challenges:

- LNG supply: There is currently very limited supply of LNG available to the transportation sector.
- LNG refueling infrastructure: There are a limited number of commercial LNG refueling stations.
- Fuel quality standards: Standards both for contaminant concentration and energy content are lacking.
- Pricing transparency: It is not always easy to know “the price” of LNG.

Policy challenges:

- Government policy and incentives are currently not seen as a level playing field, but rather are seen as favoring other alternative vehicles and fuels above NGVs.

- The current fuel tax structure is disadvantageous towards LNG, even relative to diesel.

Limited product offering and higher capital costs

There are very few engine manufacturers offering an LNG platform, either dedicated or blended (see above). To enhance adoption in this sector, more competition is needed. Cummins-Westport is currently the industry leader, but is unlikely to hold its near-monopoly on the market as other more truck and engine manufacturers are starting to offer LNG models, including Kenworth, Peterbilt, Navistar, Freightliner, Caterpillar and Volvo.

LNG trucks cost anywhere from $45,000 to $100,000 more than their diesel counterparts. Some of this cost increment is due to the small scale of production—relatively few LNG engines are manufactured—but the components of the LNG system also add to the cost. The cryogenic storage tanks are made from specialty materials such as high-nickel steel, which adds costs. While economies of scale should bring down the costs, IHS CERA does not expect to see them at parity because of the necessity of the higher-cost specialty equipment.

Competition is needed to address both of these issues. Competition simultaneously increases the number of choices available to buyers, but will also drive down costs faster, leading to faster adoption. This will certainly come from additional OEM players. However, increased offerings are already available via retrofits (turning a diesel engine into a bi-fuel engine). It is currently very expensive to have a new engine class approved by the EPA, but once approved, the capital costs of retrofits are much lower than the cost of a new truck, as low as $30,000 additional. As more engine classes are approved, more engines will become available for retrofits.

Cryogenic storage tanks weigh more

Although LNG is lighter than diesel, LNG storage tanks are much heavier. As a result, the LNG fueling system is heavier than diesel. As DOT regulations are weight-restricted, this could mean that truckers may have to carry less payload on each trip, which could in turn impact economic return. Regulatory measures could be used to avoid such disincentives. As one example, if deemed safe, LNG trucks could be given higher weight limits.

LNG supply

There are several ways to supply LNG to the HDV fleet and the vast network of pipeline quality gas means that technically it could be supplied from almost anywhere. For one thing, with the United States embarking on LNG exports, large-scale liquefaction facilities will be online within a few years, providing a potential source of LNG for the domestic trucking market.

Peak shavers are another supply possibility. There are currently 50 peak shavers with liquefaction capacity on the order of 0.3-0.4 Bcf per day in the United States. These small inland facilities were constructed to take pipeline gas at times of low gas demand, liquefy it, and store it for use during the highest demand periods. In theory, these facilities could instead provide LNG for transportation either instead of their primary purpose or in addition to their primary purpose. Currently however, they may not be suited to serving the transportation market for a number of reasons. Total capacity is quite limited and most facilities are prohibited by state regulation from offering sales to the trucking sector, since the facilities were originally dedicated to meet winter peak demand when long haul natural gas pipeline capacity can be insufficient. In addition, some do not produce LNG of a sufficient quality for the transportation sector.

But as many of these facilities are significantly underutilized for most of the year, regulatory changes combined with minimal investments in truck-loading and gas cleaning may allow for the repurposing of this underutilized equipment on non-peak days, increasing available supply for the transportation sector. The redeployment of unused capital stock would likely be welcomed as it adds revenue to the gas LDCs by allowing them to access new markets. One dilemma for the trucking industry, however, may be where to source their fuel supply on days when the peakers are required to meet peak demand.

Even all of the peak-shaving capacity, however, would not be enough for the transportation sector. In order for transportation LNG supply to grow sufficiently, continued investment in dedicated liquefaction facilities are needed. There are currently several liquefaction facilities around the country ranging from those that were designed to make LNG as the primary product to those that produce, or can produce, LNG as a byproduct.

Combined capacity between all types of facilities is less than 700,000 gallons per day (gpd), or just above 10,000 bpd of diesel equivalent, but supply potential is growing. The largest is Clean Energy Fuel's 180,000 gallon per day liquefaction facility in Boron, California. AGL Resources is currently expanding its Topock, Arizona facility, adding 100,000 gpd of capacity. Furthermore, there is 2.2 million gpd of capacity in various stages of the planning process in the United States, including Shell's 430,000 gpd liquefaction facility in Geismar, Louisiana. Shell also plans to build a facility of the same size in Ontario, Canada. If all are built, these additions will bring non-peak-shaver US capacity to roughly 3 million gpd of LNG, a drop in the bucket relative to total HDV diesel demand of 84 million gpd.

Another model has been proposed for supplying LNG at retail outlets. Under this model natural gas would be distributed to the sales facility for on site liquefaction. Instead of a handful of high-use locations, there would be many small-use facilities around the pipeline or local distribution network. The volumes delivered per customer per location would be more in line with a gas LDC's current operations, and as such this could prove more attractive. Some issues similar to those existing on the CNG side are likely regarding a gas LDC's allowable participation in such a venture. Gas LDC ownership in a facility could be full or partial and this will often affect the access type—public access, private access, or limited access.

Fueling infrastructure

Although still a challenge, fueling infrastructure is less problematic for HDVs than for other vehicle types. LNG fueling infrastructure is in its infancy, with only 66 stations providing LNG across the country, and only 28 serving the public (as of February 2013). However, these numbers will double or even triple by the end of 2013, with Clean Energy Fuels and Shell taking the lead. Clean Energy Fuels alone is on track to have 150 stations constructed by the end of 2014, mostly in partnership with Flying J truck stops.[155] Shell has teamed up with Travel Centers of America and intends to install 200 pumps at more than 100 truck stops.

IHS CERA estimates that fewer than 250 fueling stations would be needed to blanket the US lower-48's entire interstate system at 300 mile intervals. This represents a required investment of $250-$375 million, at a cost between $1-1.5 million per station (minimum). By locating stations where interstates cross, this investment could be considerably lower.

Additionally, there could be greater coordination and knowledge-sharing between gas LDCs and

[155] As of the end of 2012, Clean Energy Fuels had completed 70 stations, but only opened 11 of them.

municipal, state and federal governments. Many of the LNG stations that currently exist are owned by municipalities, who are more interested in saving money than in the payback periods. Greater dialogue and cooperation between governments and LDCs could accelerate the transition of government fleets to natural gas fuel.

In order for LNG to penetrate the transportation market, however, significant infrastructure investment needs to continue. Although many HDVs predominantly travel on the interstates, fueling infrastructure is needed off the interstate as well. This could come in the form of public access service stations, like the ones being constructed by Clean Energy and Shell, but also in the form of private fleet fueling facilities. These operate essentially as private access fueling stations, requiring a storage tank and dispensing apparatus at a minimum. Scheduled delivery of LNG has also been employed by some suppliers, whereby LNG supply is dispensed on a regular basis via mobile refueling.

Possible solutions to gas LDC participation in LNG fueling infrastructure include:

- A hybrid ownership model in which a regulated natural gas utility owns certain assets of the LNG facilities (generally the compressor, storage and auxiliaries) using a rate-based model and a third party commercial retailer owns the dispensing means (generally the land, card-reader, and retail transaction functions) using an unregulated model. The gas LDC recovers its investment in facilities and associated operations and maintenance costs through a 'services' fee that is charged to the retailer. The retailer then charges the customers for the delivered LNG using an unregulated fuel price.

- Gas LDC ownership of public access stations in which the gas LDC provides LNG service at stations that are part of their facilities, or at a nearby public location. The user pays for the fuel consumed based on a dispensed published rate per unit as established by the regulatory authority. An AGA survey in 2010 established that more than 17 gas LDCs had a special NGV or CNG rate for fuel.

- Gas LDC ownership of limited access stations, often at a customer location, in which the gas LDC provides LNG service to a limited number of vehicles. The vehicles are typically owned by one or more fleets, and generally do not include vehicles used by the general public. They may be filled using a time-fill approach if appropriate. The user pays for the fuel consumed on a per unit basis, and may be subject to a take-or-pay contract to assure a return on the utility investment.

Standards

There are very few standards applicable to natural gas in transport. Fueling infrastructure—from the diameters of nozzles to the length of hoses to the height of roofs—is not standardized. The number and type of safety measures must also be standardized, as does accounting for the amount and value of vapor return in LNG fueling. Common standards are needed to ensure that LNG use in transportation is implemented safely. Standards in other non-safety related components will help drive penetration faster.

Standards: energy content

There is a stark difference between LNG and CNG when it comes to the standard definition of the product. A standard relationship has been defined between CNG and gasoline. A standard gge is equal to 126.67 cubic feet according to the Internal Revenue Service and 5.66 pounds according to the National Institute of Standards and Technology. But there is no counterpart on the LNG/diesel side, no standard definition of a "diesel gallon-equivalent (dge)". Common definitions are needed to facilitate business transactions.

Standards: fuel quality and contaminants

Natural gas varies in its exact composition. "Tariff restrictions" are imposed by pipeline companies to protect the physical asset, but these come in a range of acceptability. Sulfur, for example, can range between approximately 8 and 300 ppm, depending on the pipeline. Most contaminants are removed during the liquefaction process, however, making this less of an issue for LNG than it is for CNG. Nonetheless, standards that specify maximum contaminant concentrations are needed in order to satisfy warranty requirements.

Standards: maintenance facilities, training, and safety

As the use of LNG grows, more facilities must be fitted out with any special equipment needed to service these vehicles. This ranges from diagnostics to ventilation to the actual technicians able to service the trucks. The current trend in LNG adoption has been towards fleet operations, and technicians dedicated to those fleets will need training and tools. But broader availability will be needed to advance the use of natural gas outside of the fleet-only space. More deals such as the one between American Power Group and Wheel Time—a major consortium of truck technicians—for natural gas service training will be needed.

Because natural gas vehicles are largely unfamiliar technology, proper handling must be taught to truck operators, fueling and maintenance personnel, and emergency responders. Maintenance facilities must be designed for safety, including special methane sensors and venting equipment for enclosed repair facilities. Cryogenic fuel tanks must be durable and able to maintain a vacuum for proper tank insulation. This is important to minimize venting and for safety in the event of vehicle collision. Fuel management guidelines must be developed to minimize natural gas venting when the truck is not in operation owing to low shipping demand, maintenance, or repair. Other technological improvements that will allow tanks to withstand higher pressures may be needed to minimize venting from pressure-release valves.

Pricing transparency

Unlike gasoline and diesel, whose prices are readily displayed at hundreds of thousands of retail outlets, retail natural gas prices are not transparent to the vehicle owner. Mechanisms must be put in place to assure consumers that they are getting a fair price. This can be accomplished privately through offtake contracts whereby the price is set either as a flat rate or as a discount to diesel. For public adoption, portals such as web pages that share pricing at public stations may be the key to greater price transparency.

Policy and regulation

Regulations need to be re-evaluated to remove impediments to natural gas use in transport. For example, some bridges and tunnels prohibit the transport of LNG while diesel fuel is allowed. Supply is also handled according to the original intention of its use. LNG produced in peak shavers is treated differently from other LNG (for example, it may not be exported) although it is the same physical product.

In particular, the tax structure for competing fuels needs to be rationalized. Both LNG and diesel are taxed on a per-gallon basis, rather than on a diesel-equivalent basis. This places LNG at a significant disadvantage considering that its energy density is lower than that of diesel—a gallon of LNG has a lower Btu content than a gallon of diesel. As a result, LNG is taxed 71% higher than diesel fuel, at $0.41 per dge versus $0.24 per gallon of diesel. The economics of LNG versus diesel look compelling even with this additional tax burden, but taxing the two fuels equally will improve LNG's economics even further. CNG and gasoline are already taxed according to energy content (on the basis of a gallon of gasoline-equivalent).

There are many existing and proposed state initiatives that support the building of natural gas fueling infrastructure and fleet and personal vehicle conversions through grants, rebates, tax credits and other cost recovery mechanisms:

- The Arkansas Energy Office of the Arkansas Development Commission provides rebates for 50% of the conversion cost up to $4,500, specifically for vehicle conversions to CNG and LNG (as well as to propane/LPG). The Arkansas Energy Office also provides rebates for qualified CNG, LNG, and propane fueling stations in the amount of 75% of qualifying costs, up to $400,000.

- Colorado offers a state income tax credit (on an annual sliding scale) for light- and medium-duty natural gas vehicles.

- The TCEQ administers the NGV Grant Program, which provides grants to replace existing medium- and heavy-duty vehicles with new, converted, or repowered NGVs. TCEQ may also award grants through the Clean Transportation Triangle Program to support the development of a network of natural gas fueling stations along the interstate highways connecting Houston, San Antonio, Dallas, and Forth Worth.

- Utah provides an income tax credit of 35% of the vehicle purchase price, up to $2,500, for an original equipment manufacturer compressed natural gas vehicle registered in Utah. It also provides an income tax credit of 50% of the cost to convert a vehicle to run on propane, natural gas, or electricity, up to $2,500.[156]

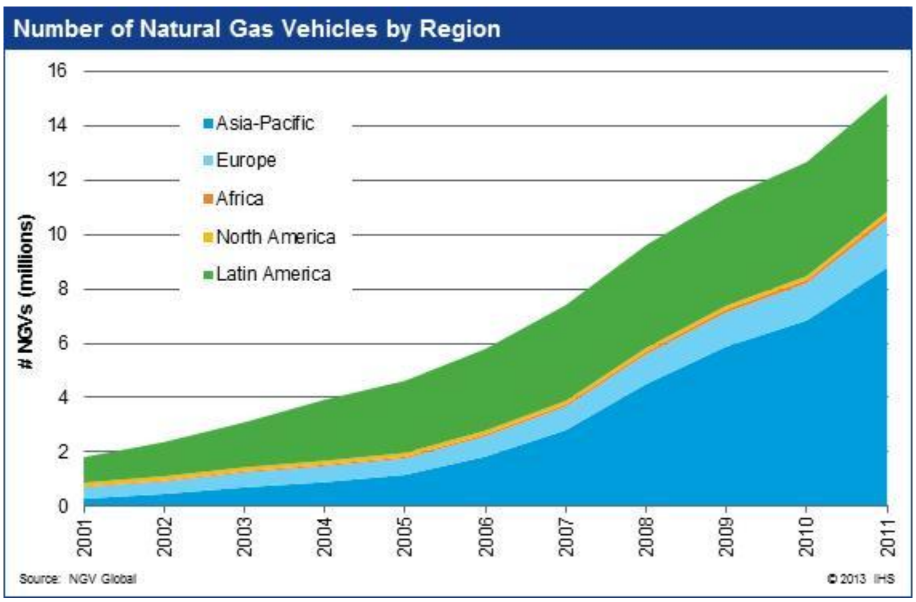
[156] Laws and incentive programs available on US Department of Energy Alternative Fuels Data Center (www.afdc.energy.gov), accessed June 21, 2013.

- Pennsylvania has pending bills for funding of fleet conversions and providing incentives for fueling infrastructure.

NGVs in other countries

Renewed interest in natural gas vehicles in the United States has been sparked by the wide gas-to-oil price differential created by the unconventional gas revolution. But natural gas vehicles have already seen success in other markets around the world (see Figure X-10). For example, the top five NGV markets globally are Iran, Pakistan, Argentina, Brazil, and India. NGVs have grown the most significantly in Asia-Pacific. The primary reasons for NGVs' success in other markets are policy and the availability and affordability of NGV conversions. Policy can include vehicle tax credits, subsidies for CNG conversion, and even mandating that certain vehicles such as taxis be CNG. For example, in cities like Delhi and Bangkok taxis are required to run on CNG. Also while in the United States CNG conversions can cost more than $5,000, in other markets CNG conversions can cost less than $1,000 and in some cases the government provides an additional subsidy to incentivize conversions. Governments around the world are looking at CNG as an opportunity to diversify the transportation fuels market and as a way to improve the poor urban air quality that plagues many of these markets.

FIGURE X.10



The market potential for NGVs in the United States

The overall LDV market in the United States is large and growing—approximately 230 million LDVs on the US roads in 2012, projected to grow to around 300 million by 2035—and it presents a big opportunity for increasing natural gas demand. All of the LDVs on the road today that consume gasoline and diesel fuel use the equivalent of 43 Bcf per day of natural gas, but it is unrealistic to expect that natural gas would displace oil in the LDV market to this extent. An extremely ambitious goal for the natural gas industry would be to have an NGV in each of the 50.4 million single-family homes that had gas service in 2009. This would add approximately 9.4 Bcf per day of natural gas demand. A more attainable goal might be to have an NGV in one-tenth of these homes, in which case about 0.9 Bcf per day would be added to natural gas demand. Even this goal would represent a five-fold increase in light-duty NGVs, given that there were only an estimated 100,000 natural gas-fueled cars and light-duty trucks in the US in 2012.[157]

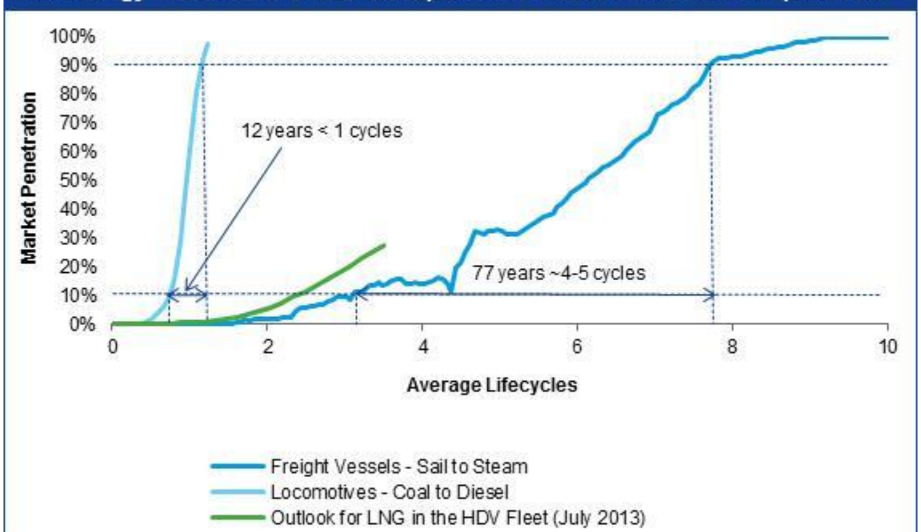
As far as MDVs are concerned, if all of the 4 million MDVs on the road in 2012 were fueled by CNG, they would consume 2.4 Bcf per day of natural gas. However, EIA estimates that actual CNG use by MDVs amounted to only 1% of total MDV fuel use, or 0.02 Bcf per day.

Finally, if all of the HDVs on the road today were fueled by LNG, they would consume 10.7 Bcf per day of natural gas. Actual HDV consumption of LNG in 2012 was estimated to be less than 0.01 Bcf per day, but IHS CERA expects rapid growth in this category, possibly exceeding 4 Bcf per day by 2035.

One of the biggest question marks is one of the least understood, and that is how quickly will consumers (heavy-duty truck owners or passenger vehicle owners) make the switch, i.e., what is the rate of adoption of a new transportation technology. There are two historical precedents on the transportation side which provide some useful boundaries. First, the switch from sail-to-steam on the open seas, where steam engines took about 80 years to go from a 10% share of the US fleet to 90% share. Given the average life of such a vessel (about 20 years), this meant a near complete penetration in about four lifecycles. On the rails, however, the transition after World War II from coal/steam to diesel locomotives took just 12 years, again to go from 10% of the locomotive fleet to 90% of the locomotive fleet, which was less than one lifecycle. Clearly the drivers, technologies and costs were different, but these two examples give historical precedent of what is possible. The IHS CERA view of LNG penetration into the HDV sector falls in-between these two examples as seen in Figure X-11.

FIGURE X.11

Technology Transitions of US Transportation Fleets-Historical Perspectives



Source: IHS CERA

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[157] US Energy Information Administration, *Annual Energy Outlook 2013.*

Natural gas in marine transportation

The shipping industry faces a costly challenge: upcoming regulations will drastically limit sulfur emissions, first in North America and northern Europe in 2015 and then globally by 2020 or 2025. At stake for the oil industry is a major market: 4 million barrels per day (mbd). Substitution of diesel (gasoil) for high-sulfur fuel oil (fuel oil) is unlikely for a number of reasons: the refining industry would struggle to supply an extra 4 mbd of diesel, and a wide oil-gas price differential opens the door to the use of natural gas. As a result two alternative solutions exist, both technologically reasonable and economically justified: dual-fuel engines that use either oil products or LNG; or smoke scrubbers, which enable the continued burning of fuel oil.

All large ports worldwide have bunker oil storage capacity and deliver fuel oil and gasoil to ships, but none except the Scandinavian ports currently deliver LNG. A significant number of ports that are near liquefaction or regasification facilities have or will soon have LNG on site. The exceptions are in the United States, where several major ports have very little if any LNG infrastructure.

The central question facing the industry is: who will invest first, ship owners or bunker retailers?

A number of players are positioned to develop LNG as a bunker fuel:

- International oil companies that currently sell bunker fuel oil and gasoil and have access to LNG;
- National oil companies that produce LNG;
- Shipping companies or ports and national authorities;
- Navies (Francisco, the fastest boat in the world that is not a speedboat, reached over 58 knots, powered by LNG);
- Even newcomers such as developing second-tier retailers and other local companies.

But—with the exception of Singapore, Rotterdam, and Gothenburg—none has made or even announced a meaningful first step.

Total potential: In the United States, coastal and inland marine vessels use the equivalent of about 0.5 Bcf per day of liquids now. Vessels that trade internationally but bunker at US ports consumed an additional 1.8 Bcf per day equivalent of liquids fuels. The total potential marine market for natural gas in the United States, based on current consumption of marine fuels, is therefore 2.3 Bcf per day.

Natural gas for rail transportation

Like HDVs, locomotives consume a lot of fuel, and can account for up to 26% of a rail company's costs operating costs. Fuel cost savings must be considered along with the costs of retrofitting ($600,000-$1,000,000) or buying a new natural gas-fueled engine (approx. $2,000,000). EIA estimates that more than 5.4 billion gallons of diesel (equivalent) was consumed by freight rail transportation in 2011. IHS CERA estimates that about 3.5 billion of these were consumed by the 24,250 Class 1 locomotives, or more than 150,000 gallons each. At potential fuel cost savings of about $1-$1.75 per gallon, capital costs could be recouped in as little as two years, or as many as 7 years.

With the outlook for natural gas prices to continue at a substantial discount from oil prices, converting a locomotive from diesel to LNG is attracting interest throughout North America. Pilot programs—from cautious to lofty— exist in a small handful of countries to switch railways to natural gas, driven by the cost savings and environmental benefits. Most famously, the "Napa Valley Wine Train" has been running on CNG since 2008. In Canada, two diesel-fueled engines have been converted to run on natural gas and Canadian National Railways—the sponsor of the pilot project—is working to develop an all-new natural gas locomotive engine and specialized tank car to carry the fuel by about 2014. Russia also announced intentions to have a gas turbine locomotive ready in 2013. If tests go well, they will produce 39 more in 2020. In January 2013, the Indian Railways Ministry announced that they will retrofit diesel locomotives to run on natural gas. There are plans to test the conversion technology on 100 diesel locomotives before converting an additional 2000 over a 5 year period. Most recently, BNSF Railway announced that it will begin a pilot program later in 2013 to test LNG in a small number of locomotives. A predecessor of BNSF, Burlington Northern Railroad, had used natural gas in some locomotives in the 1980s and 1990s.

As with other natural gas technologies, higher initial capital costs must be offset by savings in fuel costs. The cost of retrofitting a locomotive to use LNG can run between $600,000 and $1,000,000 and a new (diesel) locomotive costs approximately $2,000,000. With an LNG cost of about $2 per gallon lower than diesel, converting a locomotive from diesel to LNG would require several years to recover capital costs.

Technical hurdles compound the economic challenges. Because of the lower volumetric energy density of LNG, more volume is needed for fuel. Natural gas-fueled locomotives are being tested that would rely on tender cars carrying LNG behind the locomotive, much like coal tenders did for steam engines in the past. This additional tender would add weight and an extra car to the train, would pose technical challenges surrounding transfer of cryogenic liquids between two moving cars, and require government approvals for putting a tank of liquefied natural gas on a train car. Initially, LNG locomotives would also pose issues around interchangeability with other freight systems.

Total potential: If all diesel locomotives in operation today were converted to LNG, they would consume 1.3 Bcf per day of natural gas.

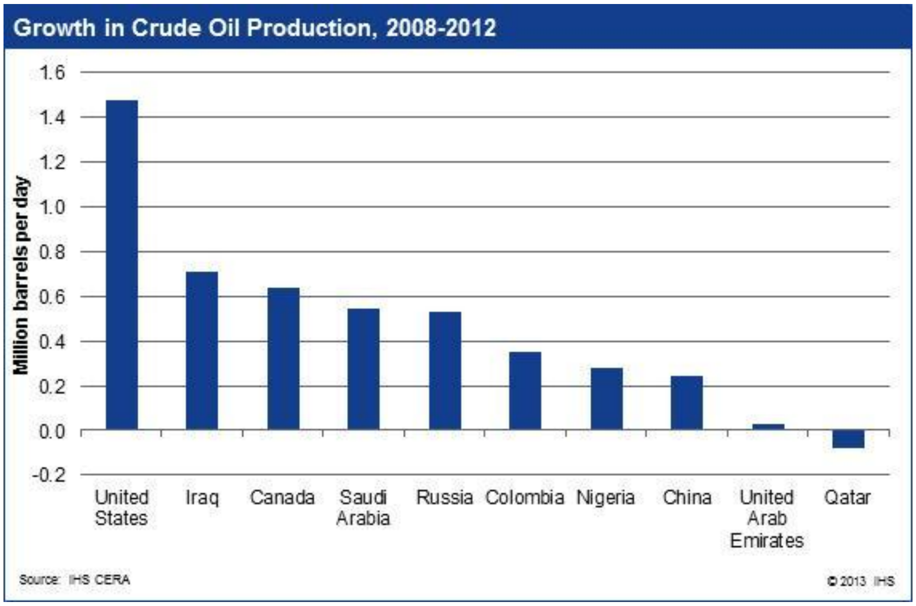
US energy security

The new abundance of natural gas in the United States has radically altered the outlook for US energy security from a supply perspective. The United States is essentially self-sufficient in natural gas, producing 92% of its total supply and importing the rest from Canada. Before the Shale Gale, increasing dependence on LNG imports had been envisioned. Instead, the United States is poised to become an exporter of LNG within a few years.

From a demand perspective, oil imports on a net basis constitute about 35% of total US oil demand, or approximately 6.4 million barrels per day in 2013. This is a reduction from its high point owing to the recession, increased efficiency of the motor fleet, and increased domestic oil production. Growing natural gas demand by one Bcf per day in the transportation sector would reduce oil imports by about 0.2 million barrels per day (assuming oil imports are displaced). Fuel diversity also contributes to energy security.

On the supply side, the transfer of unconventional gas E&P technology to US oil plays is leading to a revival in domestic oil production. Since 2008 the United States has led the world in the growth of new supplies of liquid fuels, including compared to OPEC (see Figure X.12). In fact, IHS CERA expects that Brazil, Canada, Iraq and the United States will account for 86% of global crude oil production gains from 2012 to 2020.

FIGURE X.12



Prior to the unconventional revolution, US oil production had experienced a long period of decline. From 1970 to 2008, crude oil production (including lease condensate) fell from 9.6 million barrels per day (mbd) to 5 mbd. Since then, production of "tight oil" using the same techniques pioneered for unconventional natural gas resources has increased from 100,000 barrels per day in 2003 to an estimated 2 mbd in 2012. Strong growth in tight oil production is anticipated to continue. By the end of this decade, tight oil production is expected to reach nearly 4.5 mbd, representing nearly two-thirds of domestic crude oil and condensate production.

The larger economic impact of greater domestic crude oil production will be to reduce imports and the trade deficit. Every incremental barrel that is produced domestically displaces one barrel of imported foreign crude oil, assuming fixed refining capacity, stagnant demand, and crude oil export limitations.

Long-standing concerns over US energy import dependence are being upended also as are historical energy alliances. When the United States contributes to global LNG supplies, gas-consuming countries will have more supply options, reducing the market power of previously dominant suppliers. For example, European consumers will have more alternatives to Russian gas supplies. Increasing domestic oil production will reduce US demand for oil imports and relieve pressure on world oil prices. And technology transfer to other countries is likely to increase production of unconventional natural gas and oil around the world, with transformative effects possible on global energy markets.

Implications for gas LDCs

Gas LDCs can be at the leading edge of the penetration of natural gas into the transportation sector by:

- Supporting consumer education to grow demand for NGVs which will increase the production of NGVs and bring down costs
- Supporting policies that level the playing field for all alternate fuel vehicles
- Providing fuel and fuel-related services that allow the buildout of refueling infrastructure by:
    - Finding ways to participate in the buildout and operation of both retail and commercial CNG and LNG refueling stations. Selling at regulated rates may preclude a gas LDC from capturing the natural gas to gasoline (or diesel) price arbitrage unless they can establish special rates for the commodity under NGV, CNG or LNG fuel tariffs. Alternatively gas LDCs are likely to benefit from owning facilities with on site compression/liquefaction using hybrid business models that collect services fees. Depending on the business model selected, gas LDCs will be selling either to the retail facility or directly to the consumers.
    - From a strategy standpoint, weighing the merits of home refueling versus public refueling facilities for light-duty vehicles
    - Examining the feasibility of supplying LNG through existing gas LDC-owned peak shaving facilities. In most instances, regulations need to change in order for this to happen, and fuel quality standards need to be examined and adjusted if necessary.
- Supporting sustained R&D that will advance storage and compression technologies that reduce costs

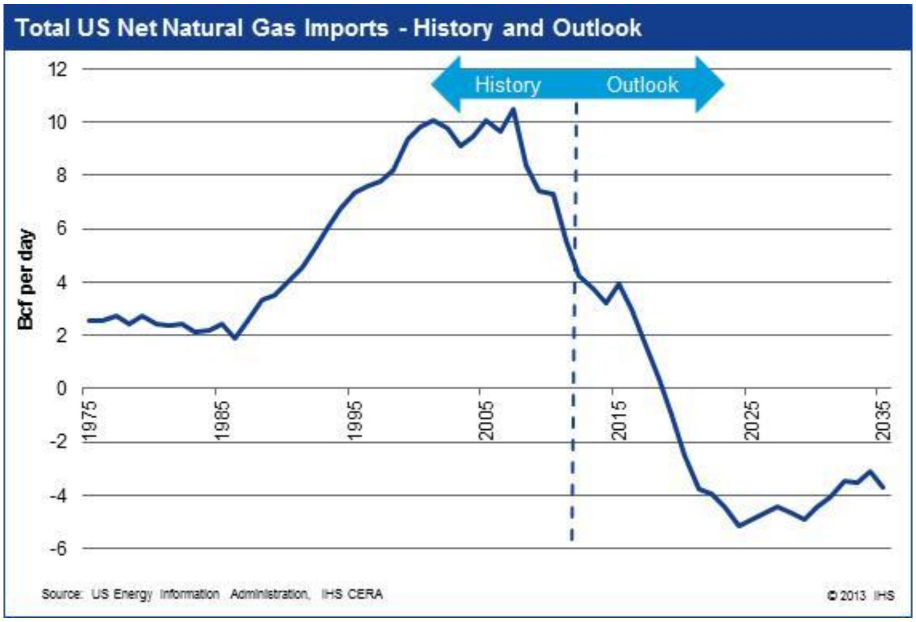
Chapter XI: Natural Gas Exports

In Brief

- The strength of US natural gas supply promises to turn the United States from a net importer of natural gas to a net exporter by 2019.
- The United States is connected by pipeline to Canada and Mexico and has imported natural gas from Canada for many years. Net imports from Canada have declined sharply over the past decade while exports of US gas to Mexico are growing.
- US lower-48 exports of LNG are approaching reality. As of June 2013, 21 exports projects had been proposed that, if built, would exceed 28 Bcf per day in total capacity. All LNG exports must be authorized by DOE and construction must be approved by FERC (for onshore facilities) or the Maritime Administration of the Department of Transportation (for offshore facilities).
- IHS CERA's analysis of US natural gas resources indicates that the US resource base is so extensive that it can support higher demand, including LNG exports, without materially affecting long-term prices.
- US LNG exports are likely to be constrained by global competition. Projects in Australia, Canada, Russia, East Africa, and elsewhere have been proposed totaling 40 Bcf per day in addition to the 28 Bcf per day of proposed US projects. Current global demand for LNG is 31 Bcf per day. It is unlikely that demand growth will be sufficient to absorb all the output that has been proposed.

The US lower-48 natural gas market is connected by pipelines to Canada and Mexico. It also has a number of LNG import terminals that were built at a time when the United States was expected to import increasing amounts of LNG to supplement stagnant domestic production. In fact, net natural gas imports peaked at 10.5 Bcf per day in 2007 and have been declining sharply ever since. In 2012, net imports were only 4.4 Bcf per day (see Figure XI.1). IHS CERA expects that the United States will be a net exporter of natural gas by 2019.

FIGURE XI.1

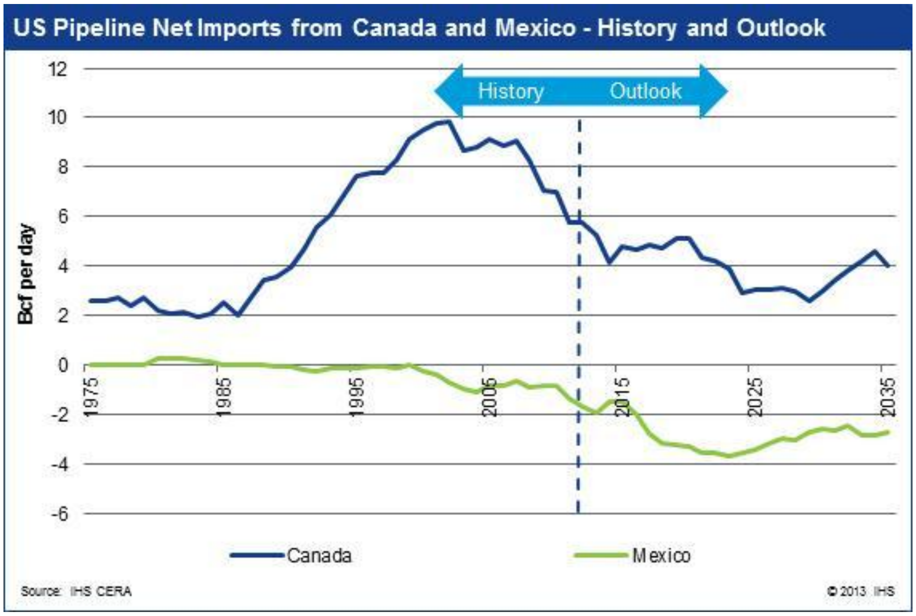


Pipeline Trade

The United States has long imported natural gas by pipeline from Canada. Net imports from Canada began a long climb in 1986, rising from 2 Bcf per day that year to a peak of nearly 10 Bcf per day in 2002 (see Figure XI.2). By 2012, net imports from Canada had declined to 5.7 Bcf per day and are expected to decline to 4.3 Bcf per day by 2021.

US gas trade with Mexico was negligible until 2000 when US gas exports to Mexico began to grow. By 2012, the United States was exporting 1.7 Bcf per day to that country. IHS CERA expects exports to grow to more than 3.5 Bcf per day by the early 2020s, after which time Mexico is expected to have developed its own indigenous unconventional natural gas resources.

FIGURE XI.2



LNG Trade

Only a few years after the United States was expected to become a major LNG importer, the abundance of low-cost domestic natural gas has suddenly made the idea of US lower-48 LNG *exports* a near reality. As of June 2013, 21 export projects had been proposed that would exceed 28 Bcf per day in total capacity.

All LNG exports must be authorized by DOE and all construction of onshore LNG facilities must be approved by FERC. LNG facilities in federal waters need to be licensed by the Maritime Administration of the Department of Transportation. By law, DOE must approve an export application unless it finds that the export is not consistent with the public interest. The burden is on DOE to make such a finding, without which the law requires issuance of the permit.

Obtaining export permits is virtually automatic if the target markets are countries that have already signed free trade agreements (FTAs) with the United States and require national treatment for trade in natural gas.[158] Applications for export to non-FTA countries are subject to more scrutiny. Most export project sponsors have sought the latter because the largest consumption markets for LNG today are in countries with which the United States does not have signed FTAs. Not taking into account South Korea -- which was the second largest LNG importer in 2012 and has had an FTA with the United States in force since March 2012 -- Japan, China, India, Spain, and Taiwan accounted for 59% of global LNG consumption in 2012.

[158] National treatment means that the parties participating in the export agreement should be treated by US Department of Energy on the same basis as US citizens. Currently the United States has 16 FTAs in force that require national treatment for natural gas trade: with Australia, Bahrain, Canada, Chile, Dominican Republic, El Salvador, Guatemala, Honduras, Jordan, Mexico, Morocco, Nicaragua, Oman, Peru, Singapore, and South Korea. Additional FTAs with a national treatment requirement for gas trade have been negotiated with Colombia and Panama, although these have not taken effect yet pending legislative action in those countries to come into compliance with the FTA requirements.

In May 2011, Sabine Pass LNG was granted permission to export LNG to non-FTA countries. DOE reserved the right, after the opportunity for a hearing and for showing good cause, to revoke or alter permission in the future if it found that these or any other LNG exports reduced the "supply of natural gas needed to meet essential domestic needs."[159] This qualification was perceived as reducing the investment attractiveness of LNG projects. Later, Christopher Smith, DOE's Principal Deputy Assistant Secretary and Acting Assistant Secretary for Fossil Energy wrote in a letter to a US Congressman that DOE has never used such authority and that it did not intend to use this authority as a price maintenance mechanism.[160]

LNG exports have been opposed by some gas user groups who fear that the increased gas demand from liquefaction facilities would increase domestic gas prices to the detriment of domestic gas consumers. Some environmental groups oppose exports because they don't want to encourage natural gas production.

In light of such opposition, DOE suspended non-FTA export license reviews until it conducted two studies to investigate whether LNG exports might not be in the public interest. The first study, delivered in January 2012 by EIA, concluded that exports could increase domestic gas prices by $0.55 to $1.22 per Mcf. The second study, by NERA Economic Consulting published in December of 2012, concluded that US LNG exports would unambiguously benefit the US economy; the higher the volume of LNG exports the greater the net economic benefit.

DOE began reviewing applications again once the public comment period on the NERA report ended on February 25, 2013. In May 2013, DOE granted non-FTA export approval to the sponsors of Freeport LNG. DOE is continuing to review applications, giving priority to projects that had both filed a non-FTA export application with DOE and had been approved to start the FERC pre-filing process.

IHS CERA's analysis of the domestic market effects of US LNG exports suggests that exports will not significantly affect US natural gas prices. As explained in Chapter I, the North American gas resource base is so extensive that it could accommodate a significant increase in production to support higher demand, including LNG export projects, without the need to access resources that are significantly higher cost and thus without materially affecting long-term prices, estimated at $4–5 per MMBtu through 2035 (constant 2012 $). It is possible, but unlikely, that the rate at which liquefaction projects come online could have short-term price effects. If LNG projects were to increase demand faster than operators could expand productive capacity, there might be short-term price spikes and/or supply bottlenecks. The long lead times associated with export projects should allow operators to anticipate the need for LNG feedgas and develop productive capacity accordingly, particularly if the expected demand is reflected in higher futures market prices. The lead times to bring on new gas supplies are much shorter than the lead time for a new $10 billion liquefaction project.

Note that this dynamic holds for any increase in demand for US natural gas—not just from LNG export projects. The US gas supply curve has become very elastic owing to the deployment of unconventional gas technologies. Significant increases in demand (from any source) can be accommodated without increasing long-term prices.

In any event, it is highly unlikely that all the proposed US liquefaction capacity will be built, as the global LNG market will not be able to absorb it. The 28 Bcf per day of proposed US lower-48 LNG export

[159] US Department of Energy Office of Fossil Energy, "Opinion and Order Conditionally Granting Long-Term Authorization to Export Liquefied Natural Gas from Sabine Pass LNG Terminal to Non-Free Trade Agreement Nations," DOE/FE Order No. 2961, 20 May 2011.

[160] Natural Gas Intelligence Daily Price Index, 3 March 2012.

capacity compares to a global market demand of about 31.3 Bcf per day in 2012. IHS expects that US LNG export capacity will reach 5.7 Bcf per day by 2020 owing to a number of factors. One is price. Even with low US natural gas prices (between $4 and $5 per MMBtu in constant 2011 dollars), once the costs for liquefaction and shipping are added, the delivered LNG is not cheap. In fact, US LNG export costs lie in the midrange of potential global project costs. They are not the most expensive, but they are not the lowest cost. For deliveries into Northeast Asia, the premium LNG market targeted by most projects, IHS CERA expects the delivered cost of US LNG to range between $10 and $14 per MMBtu. Although this delivered cost is significantly lower than current LNG prices in Asia ($11-18 per MMBtu), oil prices today are high, and LNG markets are tightening, two factors currently causing high LNG prices. IHS CERA expects lower oil prices and a more balanced LNG market in the post-2016 time period, when the US projects are scheduled to come online. For deliveries into Europe, US LNG would require a delivered price of $9–13 per MMBtu. IHS CERA expects European market prices to range between $9 and $10 per MMBtu (constant 2012 $) over 2018–35.

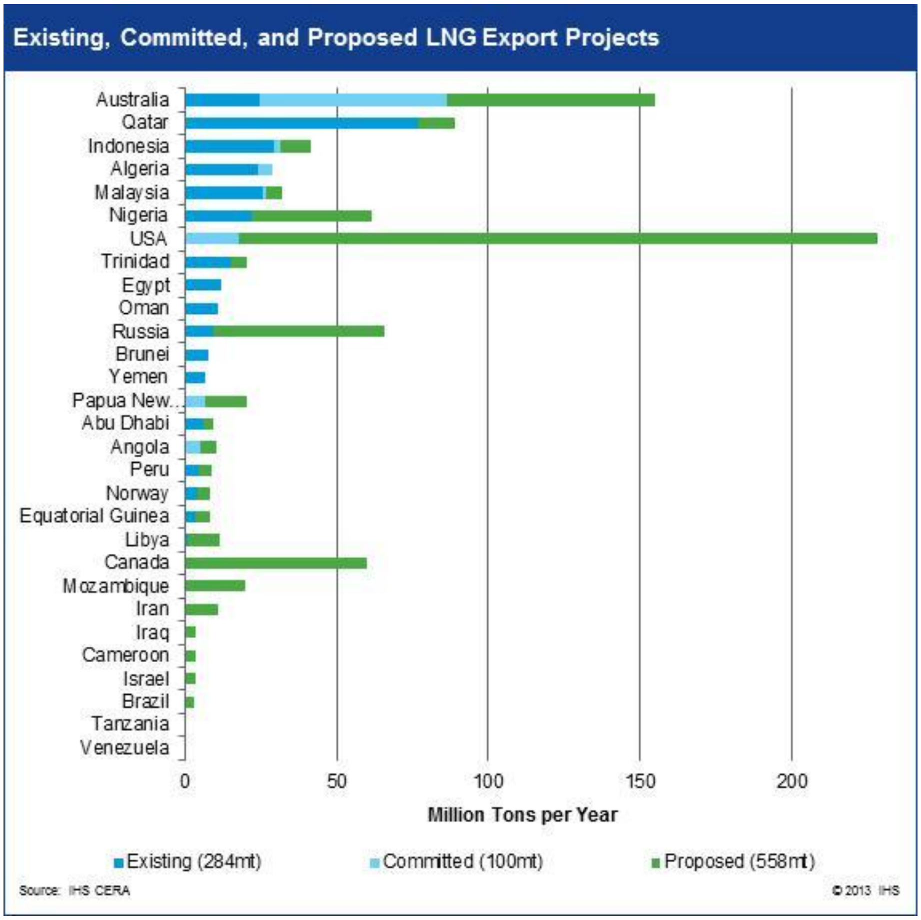
Moreover, a large number of liquefaction projects are under construction or planned in other countries that will compete with US projects for market share (see Figure XI.3). Australia is on schedule to replace Qatar as the leading LNG supplier within the next five years. Moreover, US LNG exports face competition within North America itself. Seven export projects have been proposed from western Canada, where significant amounts of gas resources are stranded unless they can be exported. Canada is accustomed to exporting energy, and its LNG projects do not face the significant “license to operate” issues that confront oil export pipelines. With final investment decisions (FIDs) for US projects planned in 2013 and 2014, significant volumes of US LNG can only become available to the market by 2017–18, by which time large volumes of liquefaction capacity currently under construction, mainly in Australia, will have already begun production.

Most of the output of these projects is already locked into long-term, typically 20-year, contracts with buyers in the main Asian LNG import markets, limiting the actual market that will remain for new suppliers to capture. Japan, the largest LNG market, has already signed for almost 70 million tons (mt), equivalent to about 9.3 Bcf per day, of firm supply in 2020, leaving potentially only 10-15 mt (about 1.3 to 2.0 Bcf per day) of demand for new supply.[161], [162] China has already signed long-term contracts for all of its expected demand (almost 40 mt, or about 5.3 Bcf per day) by 2020. There are other opportunities in the Pacific markets, including an opening supply gap in South Korea, but the main opportunity for growth in Asia comes from emerging markets, which typically have higher price sensitivity.

[161] Assuming that nuclear power generation returns, according to the current policy plan.

[162] Another 15 mt (2 Bcf per day) of capacity are under negotiation.

FIGURE XI.3



Another potential growth market, closer to US Gulf Coast projects, is Latin America, where LNG tends to be priced against European benchmarks. IHS CERA expects this market to almost triple in size to 30 mt (about 4 Bcf per day) of LNG imports by 2025, providing significant opportunities to US Gulf Coast LNG exports.

Not only will existing long-term contractual obligations of non-US suppliers limit the available market; a large slate of other proposed liquefaction projects—including projects in East Africa, Canada, Russia, Eastern Mediterranean, and further expansion of Australian capacity, will compete with US projects. Currently almost 300 mt (about 40 Bcf per day) of proposed liquefaction capacity outside of the United States is planning for FID within the next five years, competing for a finite global market. This global competition will have an effect on global LNG prices that will affect the economic viability of many proposed projects.

Implications for Gas LDCs

It is anticipated that all LNG export facilities would obtain their gas directly from interstate/intrastate pipelines and would not use local distribution networks. However, many facilities are anticipated to have bidirectional capability to both export and import LNG which will provide another layer of supply insurance for domestic markets.

Conclusions

The long-term outlook for the US natural gas market has changed radically in the past five years as unconventional technologies have been deployed to explore and develop natural gas and oil resources that had heretofore not been economically extractable. Now rather than a future of dwindling domestic natural gas supplies and ever increasing prices, the long-term outlook is for abundant natural gas resources at prices far lower than had once been expected. The United States is now virtually self-sufficient in natural gas and is expected to become a net exporter of natural gas by 2019.

Unconventional gas exploration, development and production are contributing to the economy, adding jobs, economic value, and government revenues at all levels. New high-efficiency natural gas technologies and a widening gap between retail prices of electricity and natural gas in many regions give natural gas the competitive edge for many residential and commercial applications. On average through 2035, IHS CERA expects residential electricity rates to be 3.5 times as high as residential natural gas rates, on a Btu-equivalent basis. Likewise, the projected retail price of gasoline and diesel fuel will be approximately twice the natural gas price, on a Btu-equivalent basis. Such sustained price differentials will help to increase the attractiveness of natural gas as a transportation fuel. This stands in sharp contrast to the historical market environment.

The ability to substitute natural gas for coal in power generation can help moderate the growth of harmful air emissions from the power sector. Efforts of policy makers to move the US energy mix in a less GHG-intensive direction tend to favor natural gas. From a full fuel-cycle perspective, natural gas is more energy efficient for many end-use applications than electricity.

Companies have taken time to respond to the new demand opportunities resulting from the unconventional natural gas revolution, but the expectation is now for significant growth in gas demand for power generation, industrial use, transportation, and LNG exports. Gas LDCs are in the process of re-evaluating their opportunities to serve existing customers and to expand service to new customers, as there is potential for substantial growth in gas LDC core markets. There is further growth potential in the on-going process of conversions from oil heat to natural gas; in conversions from electricity to natural gas for space heat, water heat, and cooking; in increasing natural gas' share of new residential and commercial construction; and extending gas distribution systems to new service areas.

To support these efforts, regulation and policy changes may be required. Much prevailing natural gas regulation was developed in a time of perceived scarcity and should be reviewed to identify areas that may no longer be appropriate for today's and tomorrow's natural gas markets. State governments, PUCs and gas LDCs should consider how natural gas can help improve total energy efficiency and reduce emissions. Policies that support greater use of natural gas should be underpinned by full fuel-cycle analyses of energy consumption, emissions, and costs.

Particular attention should be paid to finding approaches to manage, or reduce, the up front costs of natural gas investments, whether they be new appliances, vehicles, or gas LDC system expansions. Consumers are often unwilling to pay high up front expenses that will require multiple years to repay via lower fuel savings. Financial assistance and regulatory revision may be considered. Research into cost-reducing technologies should be supported. Improving system load factors through the use of anchor shippers to support a system expansion is another option to achieve cost reductions and improve efficiency. State PUCs and gas LDCs may wish to revisit the terms of decoupling programs to remove any disincentives for increased throughput on gas distribution systems, if increased gas consumption is to be encouraged.

Finally, with PUC support, gas LDCs can carve out new roles in serving growing natural gas markets such as offering services to industrial and power customers, or supplying LNG or CNG to vehicle refueling stations whether commercial or home-based.

The unconventional natural gas revolution has created a new set of options for natural gas to play a bigger role in the US energy mix and economy. Working together, gas LDCs, their customers and regulators can develop strategies to maximize the benefits of the new environment for natural gas.

Appendix 1: Biographies

Principal Authors and Analysts

Rita Beale, Senior Director, IHS Power, Gas, Coal and Renewables, is a consulting practice leader for this Energy Insight Business Line. She has focused on energy for more than twenty-five years in professional services, financial services, and the energy industry. Prior to joining IHS, as an energy analyst, Ms. Beale covered oil and gas commodity markets at Lehman Brothers and Goldman Sachs; as a consultant at Arthur Andersen and Energy Ventures Analysis Inc., she led engagements for institutional clients; and as an energy trader, Ms. Beale served as Vice President leading two different wholesale power trading organizations in the competitive marketplaces of ERCOT and WECC. Rita also has experience optimizing diverse natural gas storage assets and structuring complex bilateral energy supply deals. Ms. Beale has an MS in mineral economics from the Colorado School of Mines and BS in geology from Rider University. Most recently at IHS, she contributed to a public report, *The Role of Banks in Physical Commodities*.

Kenneth Yeasting, Senior Director, IHS North American Natural Gas, is an expert on the interstate natural gas pipeline and storage industries and also specializes in eastern North America gas and power markets. Mr. Yeasting focuses on issues related to gas prices and basis; pipeline flows and development; storage usage and development; the impacts of liquefied natural gas on gas prices; gas flows and the need for new infrastructure. Before joining IHS CERA, Mr. Yeasting held a number of executive positions at ANR Pipeline Company and the Michigan Consolidated Gas Company. Mr. Yeasting holds a BBA and an MBA from the University of Michigan.

Mary Lashley Barcella, Director, IHS North American Natural Gas, follows North American natural gas markets, focusing on long-term outlooks, pricing, economics, and policy. Dr. Barcella has more than thirty years' experience in energy market, policy, regulatory, investment, and geopolitical analysis, as well as macroeconomic forecasting. Previously she held positions at the American Petroleum Institute, the American Gas Association, and several energy consulting firms. She holds a BA from Vanderbilt University and an MA and a PhD in economics from the University of Maryland.

Yanni He, Associate, IHS North American Natural Gas, follows North American natural gas storage fundamentals and supports market forecasting. Ms. He also tracks the interrelationship between natural gas price behaviors and storage activities, as well as gas demand from the power sector coal displacement. Prior to joining IHS CERA, she worked at IHS Global Insight, focusing on the regional economic impact evaluation of capital-intensive investments especially in the oil, gas, and chemical sectors. Yanni also has experience in macroeconomic forecasting and econometric modeling. Ms. He holds a BS from Shanghai International Studies University and an MA from Brandeis University.

Keith McWhorter, Associate, IHS North American Natural Gas, is an expert in North American natural gas markets with a focus on supply research and modeling, liquefied natural gas exports, and the western US and Canadian regional markets. He also assists with Monthly Briefings and scenario analyses, and provides support for consulting projects. Prior to joining IHS CERA, Mr. McWhorter worked on numerous natural gas and solar energy projects while completing his graduate studies. Mr. McWhorter holds a BA from Williams College and an MBA from the FW Olin Graduate School of Business at Babson College.

Senior Advisors

Daniel Yergin, Vice Chairman of IHS Inc. and Founder of IHS Cambridge Energy Research Associates (CERA), is an expert on global energy markets. Dr. Yergin is the author of *The Prize: The Epic Quest for Oil, Money, and Power*, which received the Pulitzer Prize. His other books include *Commanding Heights: The Battle for the World Economy*. His most recent book is *The Quest: Energy, Security and the Remaking of the Modern World*. Dr. Yergin received the United States Energy Award for "lifetime achievements in energy." He received a PhD from Cambridge University, where he was a Marshall Scholar.

Timothy Gardner, Vice President & Global Head IHS Power, Gas, Coal and Renewables, has 20 years of experience as a management consultant, focusing principally on energy utilities. Tim specializes in the areas of strategic planning, marketing, shareholder value analysis, mergers, and business alignment. He has broad experience with industries operating in a transitional regulatory environment, including trucking, railroads, passenger transportation, natural gas, and electric power. Before joining IHS, he held senior positions at Booz and Co, PHB Hagler Bailly, Arthur Andersen, Amtrak, and the Cummins Engine Company. He holds a BA in political science from Swarthmore College, an MA from Oxford University where he studied as a Rhodes Scholar, and a JD from Yale Law School.

John Larson, Vice President & Global Head, IHS Economic and Country Risk, leads economic analyses and impact assessments on a wide range of critical policy issues, focusing on energy, chemicals, healthcare, and automotive industries. He possesses more than 15 years of experience in delivering economic and data-driven solutions to both private and public sector clients. Most recently, Mr. Larson has led a series of studies that have examined the economic contribution of the offshore oil & gas industry, the role of independent oil & gas producers in the US economy, the economic impact of the drilling moratorium following Deepwater Horizon, and the economic contribution of unconventional oil and gas production to the broader US economy. Mr. Larson holds a BA in economics and history and a Masters of Public Policy from the Thomas Jefferson Program in Public Policy; both are from the College of William and Mary.

Lawrence J. Makovich, IHS Vice President and Senior Advisor for Global Power, is a highly respected expert on the electric power industry. He is an authority on electricity markets, regulation, economics, and strategy. His current research focuses on electric power market structures, demand and supply fundamentals, wholesale and retail power markets, emerging technologies, and asset valuations and strategies. Dr. Makovich has been a lecturer on managerial economics at Northeastern University's Graduate School of Business. He holds a BA from Boston College, an MA from the University of Chicago, and a PhD from the University of Massachusetts.

Dr. Makovich is currently advising or has recently advised several large utilities in major strategic engagements and multiple governments including China and Brazil; he has testified before the US Congress. Recent IHS CERA Multiclient Studies include, *Beyond the Crossroads: The Future Direction of Power Industry Restructuring*, *Crossing the Divide: The Future of Clean Energy*, *Fueling North America's Energy Future: The Unconventional Natural Gas Revolution and the Carbon Agenda, Smart Grid: Closing the Gap between Perception and Reality*.

Appendix 2: Glossary of Acronyms

ACEEE: American Council for an Energy-Efficient Economy

AFUE: annual fuel utilization efficiency

AGA: American Gas Association

AGF: American Gas Foundation

ASHRAE: American Society of Heating, Refrigerating and Air-Conditioning Engineers

Bcf: billion cubic feet

Bd: barrels per day

BEV: battery electric vehicle

Btu: British thermal unit

CAA: Clean Air Act

CAFÉ: Corporate Average Fuel Economy

CBECS: Commercial Building Energy Consumption Survey

CBM: coal bed methane

CCGT: combined cycle gas turbine

CCS: carbon capture and sequestration

CDD: cooling degree-day

CES: clean electricity standard

CHP: combined heat and power

CIAC: contributions in aid of construction

CI: compression injection

CNG: compressed natural gas

CO_2: carbon dioxide

CO_2e: carbon dioxide equivalent

COP: coefficient of performance

CRC: Coordinating Research Council

CSP: concentrating solar power

CT: combustion turbine

DG: distributed generation

Dge: diesel gallon-equivalent

DOE: Department of Energy

DOT: Department of Transportation

DRI: direct reduced iron

EDC: ethylene dichloride

EER: energy efficiency ratio

EF: electric arc furnace

EIA: Energy Information Administration

EOR: enhanced oil recovery

ERCOT: Electric Reliability Council of Texas

FB: fuel blending

FERC: Federal Energy Regulatory Commission

FFV: flexible-fuel vehicle

FPC: Federal Power Commission

FTA: free trade agreement

GDP: gross domestic product

Gge: gasoline gallon-equivalent

GHG: greenhouse gas

GHGRP: Greenhouse Gas Reporting Program

GTL: gas-to-liquids

HDD: heating degree-day

HDV: heavy-duty vehicle

HRSG: heat recovery steam generator

HSPF: heating season performance factor

ICC: International Code Council

ICE: internal combustion engine

IGCC: integrated gasification combined cycle

ISO: independent system operator

ISO-NE: Independent System Operator-New England

JOGMEC: Japan Oil, Gas and Metals National Corporation

KVG: Kennebec Valley Gas

kW: kilowatt

kWh: kilowatt-hour

LCOE: levelized cost of energy

LDC: local distribution company

LDV: light-duty vehicle

LEED: Leadership in Energy and Environmental Design

LNG: liquefied natural gas

M&NE: Maritimes & Northeast Pipeline

MATS: Mercury and Air Toxics Standards

Mcf: thousand cubic feet

MDV: medium-duty vehicle

MECS: Manufacturing Energy Consumption Survey

METI: Ministry of Economy, Trade and Industry (Japan)

MH: methane hydrates

MIPD: Major Industrial Plant Database

MJ: megajoule

MMBtu: million Btu

MMcf: million cubic feet

MPGe: miles per gallon-equivalent

MSA: Metropolitan Statistical Area

MTO: methanol-to-olefin

MTP: methanol-to-propylene

MW: megawatt

MWh: megawatt-hour

NAAQS: National Ambient Air Quality Standards

NAESB: North American Energy Standards Board

NGCC: natural gas combined-cycle

NGL: natural gas liquid

NHTSA: National Highway Traffic Safety Administration

NO_X: nitrogen oxide

NSPS: New Source Performance Standard

O&M: operation and maintenance

OEM: original equipment manufacturer

PBR: permit by rule

PET: polyethylene terphthalate

PEV: plug-in electric vehicle

PGC: Potential Gas Committee of the Colorado School of Mines

PHEV: plug-in hybrid electric vehicle

PM: particulate matter

PMI: Purchasing Managers' Index

PUC: public utility commission

PURPA: Public Utilities Regulatory Policy Act of 1978

PV: photovoltaic

PVC: polyvinyl chloride

RES: renewable electricity standard

RFS: renewable fuels standard

RGGI: Regional Greenhouse Gas Initiative

RTO: regional transmission operator

SCPC: supercritical pulverized coal

SEER: seasonal energy efficiency ratio

SI: spark ignition

SO2: sulfur dioxide

TCEQ: Texas Commission on Environmental Quality

Tcf: trillion cubic feet

Tg: teragrams

USGBC: US Green Buildings Council

USGS: US Geological Survey

VCM: vinyl chloride monomer

VMT: vehicle-miles traveled

WTI: West Texas intermediate crude oil

WTW: well-to-wheels

