From Reservoir to Burner Tip
A Primer on Natural Gas

Natural gas is a combustible, gaseous mixture of simple hydrocarbon compounds, usually found in deep underground reservoirs of porous and permeable rocks. Natural gas is a fossil fuel composed largely of methane. A molecule of methane, the simplest and lightest hydrocarbon, consists of one carbon atom surrounded by four hydrogen atoms. Natural gas also contains lesser amounts of "higher" hydrocarbon gases, that is, those of greater molecular weight, namely ethane, propane, butane, isobutane and pentane (together commonly referred to as C_{2+}), as well as variable concentrations of nonhydrocarbon gases, namely carbon dioxide, nitrogen, hydrogen sulfide and helium (see sidebar, *Composition of Natural Gas*). Natural gas is the cleanest burning fossil fuel, producing smaller amounts of combustion by-products than either coal or refined oil products.

Why Is Natural Gas Important?

Natural gas has become the "fuel of choice" in many residential, commercial and industrial applications. Furthermore, natural gas has become particularly important in electric power generation. The natural gas you conveniently consume in your home or business is the end result of an entire industry working together to find, produce and deliver a safe, clean and reliable energy resource.

The first practical use of natural gas in the United States dates from 1821 in Fredonia, New York, where a crudely drilled well and hollowed-out log pipes were used to deliver gas from a natural seep to nearby homes for lighting.[70] Not until the 1880s, however, did natural gas for home heating and lighting and for industrial use become prevalent. By the late 1940s natural gas had all but replaced the use of "illuminating" gas manufactured from coal and wood. The transition was facilitated in part by federal regulations that discouraged oil field operators from wasting natural gas by venting and flaring. An unknown but likely enormous volume of gas resource was lost through such practices. Nevertheless, natural gas became a marketable commodity, and production flourished. In the years following World War II, the interstate pipeline system, which was begun in 1925, was greatly expanded, thereby bringing natural gas service to consumers all over the Lower 48 United States.

According to statistical data from the U.S. Department of Energy's Energy Information Administration (EIA) for 2008, natural gas satisfied 24 percent of the nation's energy demand (consumption), moving ahead of coal, which remained steady at 22.6 percent. Crude oil and natural gas liquids, while still accounting for the largest share, declined from a recent high of 40 percent (2004–06) to 37.4 percent. Nuclear power rose slightly to 8.5 percent, and hydropower and renewables totaled 7.4 percent.[71]

Composition of Natural Gas

	Chemical Formula	Typical Composition
Hydrocarbon gases		
Methane	CH_4	80–95%
Ethane	C_2H_6	2.5–7%
Propane	C_3H_8	1–3%
Butane	C_4H_{10}	1–3%
Pentane	C_5H_{12}	trace
Hexane	C_6H_{14}	trace
Nonhydrocarbon gases		
Carbon dioxide	CO_2	1–2%
Nitrogen	N (or N_2)	1–4%
Hydrogen sulfide	H_2S	variable
Water vapor	H_2O	variable
Helium	He	trace

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70. Peebles, M.W.H., 1980, Evolution of the Gas Industry: New York, New York University Press, 235 p.
71. Energy Information Administration Office of Energy Markets and End Use, 2009, Annual Energy Review 2008: U.S. Dept. of Energy, Energy Information Administration, Rept. DOE/EIA-0384(2008), June, 407 p. Available online at http://www.eia.doe.gov/aer.

Where does our natural gas come from? First, consider that well over one-half of all the crude oil Americans consume annually must be imported—from more than 35 countries—and 65 percent of those imports come from OPEC and Persian Gulf states. Canada, however, remains our largest single source of imported oil. In contrast, about 85 percent of all natural gas consumed in the U.S. comes from domestic onshore and offshore sources—20 trillion cubic feet (Tcf) out of 23 Tcf consumed in 2007 and 21.5 Tcf out of 23.2 Tcf consumed in 2008. The remainder is imported from Canada via pipelines (3.30 Tcf in 2007 and 2.98 Tcf in 2008, net after exports) and from six to eight other foreign countries via ocean-going tankers carrying liquefied natural gas, or LNG (a record 771 billion cubic feet, Bcf, in 2007 and 352 Bcf in 2008).[71]

Four interdependent segments of the natural gas industry are involved in delivering natural gas from the wellhead to consumers. *Exploration and production* ("E&P") companies explore, drill and extract natural gas from the ground. *Gathering and processing* ("midstream") companies connect the wellheads to *transmission* companies, which operate the pipelines linking the gas fields to major consuming areas. *Distribution* companies are the local utilities that deliver natural gas to customers. *Marketing* companies serve as intermediaries between production companies and ultimate customers.

The flow chart in Figure 256 provides convenient reference points for the following discussion of the journey of natural gas from the reservoir to the burner tip.

How Natural Gas Forms

According to prevailing scientific theory, the natural gas that is produced commercially today formed millions of years ago when very small plant and animal remains were buried by mud and silt at the bottoms of oceans and lakes. Layers of sediment and plant and animal matter that slowly built up became deeply buried over time until the pressure and heat resulting from the weight of the overlying sediment eventually converted this organic matter into natural gas and crude oil. Bacteria also are intimately involved in this *generation* process, which continues to this day in modern swamps, peat bogs, wetlands and lakes, large river deltas and in some deep ocean basins. Through time, underground forces cause the buoyant hydrocarbons to move slowly, or *migrate*, out of their *source rocks* and into porous and permeable *reservoir* rocks, where they accumulate and become *trapped* if impermeable *seal*s are present. Within a given basin or region, these four essential components—source rocks, reservoirs, trapping mechanisms and seal rocks—comprise what geologists call a *petroleum system*, which may contain oil alone, gas alone or oil and gas together.

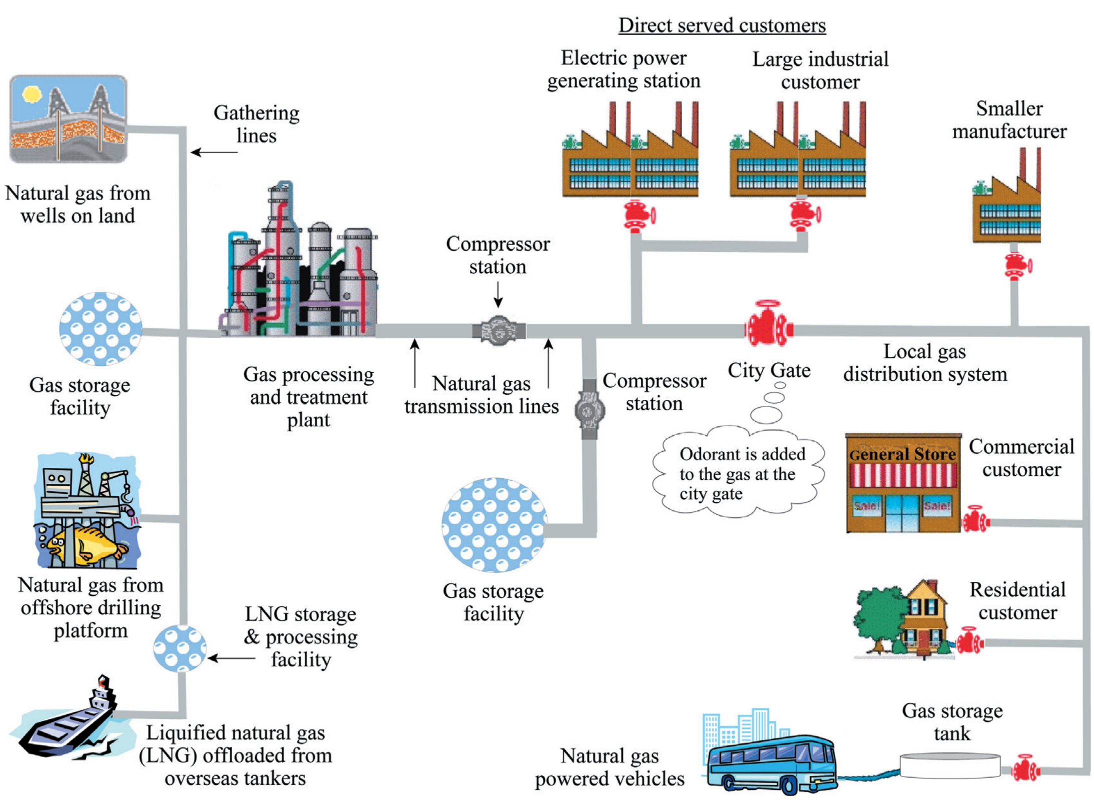


Figure 256. The journey of natural gas from reservoir to burner tip. Used by permission of Cycla Corporation.

Gas accumulates in two types of reservoirs. *Conventional* or *traditional* reservoirs include *clastic* sedimentary rocks such as porous sandstone, siltstone and conglomerate, and *carbonates* (limestone and dolomite). *Unconventional* reservoirs include coalbeds, organic-rich marine and lacustrine (lake-formed) shales and low-permeability sandstones. The grains in these "tight" sandstones have been so pervasively cemented together with silica or carbonate that high-pressure, artificial *stimulation* or *hydraulic fracturing* is required to create permeable pathways that allow the gas to flow out of the sand's intergranular pore spaces to the wellbore. Coalbeds and organic-rich shales, which are both reservoirs *and* self-generating source rocks, also usually require stimulation. In rare cases, natural gas has migrated into naturally fractured igneous and metamorphic rocks.

In industry terminology, natural gas occurring alone, without oil, is called *nonassociated* gas, whereas *associated* gas occurs with crude oil. When oil is pumped to the surface, the natural gas dissolved within it is released and is referred to as *casinghead* gas.

How Natural Gas Is Found and Produced

Exploration

Knowing how natural gas forms and accumulates, how then do we find it and produce it? Many E&P companies are committed to the challenge of finding natural gas and delivering it to consumers. They employ geologists and geophysicists to locate *prospects* where natural gas and other hydrocarbons might exist underground in economically recoverable quantities. The explorers increase their chances of success by analyzing many forms of evidence, including rock samples and fossils from strata exposed on the surface and from cores recovered from other exploration wells, results of previous drilling, and various types of remotely sensed geophysical data, such as gravity, magnetism, natural radioactivity and rock responses to electrical currents and sound waves. Prospects are then screened according to risk versus potential reward. Only those meeting strict budgetary and technical criteria will be drilled.

Still another crucial hurdle must be cleared, however, before a prospect can be drilled. Land professionals with the E&P companies must secure the legal rights to the gas resource as well as physical access onto the land surrounding the locations of proposed exploration wells. Quite often, though, the *mineral estate* has become *severed* from the *surface estate*—that is, the legal rights to the minerals and to the land surface are owned by different parties, be they private individuals, mineral and timber companies, state and local governments, the federal government, or Native American tribes. Because of this *split estate*, securing both surface access (typically through one-on-one negotiation) and mineral rights (commonly through government-regulated leasing procedures) can be extremely complicated and time-consuming but, nonetheless, necessary so that the rights and interests of all involved parties are accommodated.

Exploration prospects are the most risky. Tens of millions of dollars may be required to drill a single *wildcat* well in a previously untested area, where the chance of success may be no more than 5 to 20 percent. Target reservoirs may lie up to 30,000 ft below the ground surface or seabed. Explorers have adapted their drilling strategies to virtually every type of setting where natural gas may have accumulated—over 175 miles offshore in water as deep as 9,000 ft, below a busy Mid-Continent metropolitan area, on a remote rabbit-infested stretch of Rocky Mountain rangeland, in the midst of coal-mining operations in Appalachia, or on desolate, frozen tundra above the Arctic Circle in Alaska. The *drilling rigs* used to bore holes deep into the rock strata are technological marvels. Drilling tools and techniques are continually being improved in order to drill more quickly, more accurately and more safely; to better access the reservoirs; to deal with the extreme temperatures and pressures encountered in deep strata; to control costs; and to minimize the surface "footprint" of drilling operations, both onshore and offshore. Drilling multiple *horizontal* or *lateral* wells and *extended-reach* wells from a single drilling pad has become a desirable and even necessary option in many cases.

If the wildcat well does not find hydrocarbons in paying quantities, it is declared a *dry hole* and subsequently *plugged*, a required procedure wherein, before being capped, the wellbore is filled with cement or other impervious material to prevent potential flow of fluids between formations or to the surface.

A successful well is termed a *discovery*. Nearly 3,400 gas exploration wells were drilled in 2007, an all-time record, and 2,900 were drilled in 2008. These wells achieved a record total drilled footage of 20 million ft in 2007, for an average depth of 5,900 ft per well.[71] With better geology, geophysics and geochemistry behind the selection of drill sites, the overall success rate for exploration wells has improved markedly over the last decade, from 35 percent to more than 65 percent. The pace of new well permit applications and the number of new wells drilled in many areas of the country dropped off considerably during the second half of 2008 and into 2009 as a consequence of the economic recession.

The number of commercial rigs reported drilling for gas and oil across the country varies from week to week, depending on the season, availability of rigs, availability of funding, gas prices and demand. The number of rigs drilling for natural gas each year since 1994 has exceeded those drilling for oil. At any given time, more than 80 percent of active rigs are drilling for natural gas. The average number of active gas-directed rigs totaled 1,466 in 2007 and 1,491 in 2008.

Development

Once the productive capacity of a well has been established through testing, which can last for months, it is typically *shut in* until it can be connected to a *gas-gathering system*, a network of small-diameter pipes that collect raw gas from a number of wells and deliver it to a treatment plant or, in some cases, directly to a pipeline. State regulations usually permit an operator to *flare*, or safely burn off, the gas from a new well during testing.

Much additional work and expense then are required to bring the discovery to market. *Delineation* wells are drilled to define the subsurface areal extent of the productive reservoir and to locate additional *pools* of hydrocarbons. The results of those wells are integrated with other technical information into a strategy for establishing commercial production. Less risky *development* wells then are drilled, *completed* and *stimulated* with special surface and downhole equipment and materials to induce hydrocarbons to flow (*produce*) safely and efficiently from the reservoir into the wellbore, then up through the *wellhead* and into a gathering system. Development wells now typically have a 92 percent chance of success. EIA estimates that more than 29,200 gas development wells were drilled in 2007 and 29,700 in 2008. These achieved record total drilled footages of nearly 193 million ft in 2007 and 195 million ft in 2008.[71]

Production

Gas Fields

Any number of development wells—from one to several hundred—producing gas from one or more formations in an area delineated by a controlling geologic structure or type of trap comprise a *gas field*, whose operation and boundaries are governed by state regulations.

According to industry's classification, the volume of gas recoverable from a developed field can vary from 187 MMcf (million cubic feet) to as much as 50 Tcf ("supergiant"), although discoveries of the latter are extremely rare any more. Most of our largest gas fields classified as "giants"—containing more than 3 Tcf—were discovered between 1925 and 1950. Most giant fields discovered within the last decade have been found in the Gulf of Mexico. Statistically, only comparatively smaller accumulations likely will be discovered in the future in our mature gas-producing regions, as they are now, at least onshore. For this reason, industry must drill more wells each year—and often drill deeper—to find sufficient new supplies to meet consumer demand.

In standard oil field practice, the fluids produced from development wells are separated using treatment equipment into natural gas, liquid hydrocarbons (crude oil and condensate), nonhydrocarbon gases and water. Oil and condensate are pumped to market through pipelines; oil can be stored in tanks for later transport by truck, rail or ship. The gas flows into separate pipelines.

In some cases, the associated natural gas that is separated from the crude oil is more valuable for maintaining pressure levels within the oil reservoir than it is for sales. This gas then is *reinjected* in order to enhance oil productivity. About 3.8 Tcf of the total 25 to 26 Tcf of natural gas that is extracted and separated annually as *gross withdrawals* is reinjected for repressurization, principally on the North Slope of Alaska (approximately 3 Tcf), where no sales-gas transportation infrastructure yet exists, and to a lesser extent in the Lower 48 States, mostly in Texas, California, Wyoming, Louisiana and Colorado.[71, 72]

Stranded Gas

Some natural gas, although technically producible, cannot be produced and delivered to market because of its low quality, remote location or the fact that no large-volume market for it exists within a reasonable transport distance. If it cannot be produced and consumed for more than onsite lease use or for local domestic use, this *stranded* gas must be either shut in or, if associated with oil production, reinjected or wasted by flaring.

Subquality or *low-Btu* natural gas contains excess concentrations of various nonhydrocarbon contaminants, principally carbon dioxide (CO_2), nitrogen (N_2), hydrogen sulfide (H_2S) and even helium. In large amounts, these undesirables act to lower the heat content of natural gas to less than 950 Btu per scf (standard cubic foot), the minimum specification generally required for pipeline transportation, thus rendering the gas unsuitable for nearly all purposes. Furthermore, these contaminants can cause serious operational problems in the field, such as health and fire hazards (H_2S) and corrosion-induced wellbore casing and pipeline leakage. The Gas Technology Institute defines subquality gas as having one or more of the following characteristics—≥2 percent CO_2 content, ≥4 percent nitrogen and ≥4 ppm (parts per million) H_2S. If such gas cannot be economically upgraded to pipeline quality or blended with higher quality natural gas, it remains "behind pipe."

The volume of gas in the ground that qualifies as low-Btu gas is substantial. Researchers speculate that high-nitrogen gas may constitute 60 Tcf, or 25 percent of U.S. proved

72. Energy Information Administration Office of Oil and Gas, 2009, Natural gas annual 2007: U.S. Dept. of Energy, Energy Information Administration, Office of Oil and Gas, Rept. DOE/EIA–0131(07), January, 185 p.

reserves.[73] In the larger picture, approximately one-fifth of the world's total gas reserves likely is highly contaminated with CO_2.[73, 74]

Gas processors have developed several exotic technologies to treat and upgrade low-Btu gas in large-scale centralized facilities—cryogenic separation, membrane separation, adsorption and absorption. Research also is under way to develop affordable, small-scale, mobile treatment units, for nitrogen rejection in particular, for more widespread field and well-site applications.[75] Operators have even successfully demonstrated direct use of subquality gas, without treatment, for small-capacity, onsite power generation via gas engines and turbine-driven generators modified to run on very lean gas mixtures.

Remotely located gas accumulations, onshore and offshore, remain stranded until such time that a gas pipeline can be built or the gas can otherwise be converted into a transportable and marketable form, either through *liquefaction* into LNG, *compression* into CNG (compressed natural gas) or CGL (compressed gas liquids, an emerging technology), or *reforming* via GTL (gas to liquids) into synthetic liquid hydrocarbon fuels (ultralow-sulfur diesel, naphtha) and petrochemical feedstocks (methanol, dimethyl ether). An intriguing new conceptual technology under development aims to pelletize gas into a solid natural gas hydrate (NGH) for marine tanker transport and then regasify (dissociate) it back into gaseous form at the delivery point.

Producing Wells

The total number of producing natural gas wells has risen steadily over the years but has jumped substantially since 1999; they now total nearly 468,000. Overall average productivity of these wells was about 41.4 MMcf (million cubic feet) per well in 2007 and 2008, or on a daily production basis about 113 Mcfd (thousand cubic feet per day) per well.[71] Of course, productivities of individual wells can range over five orders of magnitude.

What may be surprising is the fact that well over two-thirds of these wells produce at rates substantially less than the average cited above. The Interstate Oil and Gas Compact Commission refers to these as marginal or stripper wells.[76]

73. Bhattacharya, S., K.D. Newell, W.L. Watney, and M. Sigel, 2008, Low-cost plant upgrades marginal gas fields: Hart's E&P, v. 81, no. 8 (August), p. 102-103.

74. Golombok, M., and D. Nikolic, 2008, Assessing contaminated gas: Hart's E&P, v. 81, no. 6 (June), p. 73-75.

75. Bhattacharya, S., K. Newell, W.L. Watney, and M. Sigel, 2009, Field tests prove microscale NRU to upgrade low-Btu gas: Oil & Gas Journal, v. 107, no. 40 (October 26), p. 44-53.

76. Interstate Oil and Gas Compact Commission, 2008, Marginal wells—Fuel for economic growth, 2008 report: Oklahoma City, Interstate Oil and Gas Compact Commission, 52 p. Available at www.iogcc.state.ok.us.

They produce at rates less than 60 Mcfd of gas or 10 bpd (barrels per day) of oil. In 2007, 322,160 gas wells identified by the IOGCC as marginal (out of 452,768 total gas wells producing) flowed at an average rate of only 15 Mcfd. Nonetheless, together they contributed over 1.76 Tcf of gas, or nearly 11 percent of the total 16.2 Tcf of gas production from the 28 states, led by Texas, who reported marginal-well production. Nationally, stripper gas wells accounted for nearly 9 percent of total gas production.

Because of their extremely low productivity, stripper wells cannot be operated economically by the major E&P companies or by the larger independents. Of the smaller independent companies who do operate them, most are "mom and pop" operators whose livelihood is largely dependent on maintaining low but steady production rates as profitably and as long as possible without resorting to well-remediation procedures, which in most cases are cost-prohibitive for them. Still, between 3,500 and 4,500 marginal gas wells and 11,000 to 14,000 marginal oil wells ultimately are plugged and abandoned every year.

Marketed Production

Thirty-two states produced natural gas in 2007 and 2008. The Gulf of Mexico, together with Texas (onshore), Wyoming, Oklahoma and New Mexico, accounted for 70 percent of total *marketed gas production* of 21.5 Tcf. Marketed production is gross withdrawals less the volumes that are reinjected, flared and removed as impurities. *Dry gas* is the volume of gas—almost entirely methane—resulting from removal of natural gas liquids from marketed production. Marketed production and dry-gas production are the two quantities most often used for statistical analysis. For 2008, EIA[71] summarized the nation's (estimated) gas production as follows:

	Volume (Bcf)
Gross natural gas withdrawals:	
From natural gas wells	19,399.7
From crude oil wells	6,646.8
Total withdrawals	26,046.4
Reductions:	
Reinjection for repressurization	3,817.4
Nonhydrocarbon gases removed	644.0
Volumes vented and flared	129.8
Marketed gas production	21,455.2
Extraction losses (resulting from removal of natural gas plant liquids)	881.2
Dry-gas production	20,574.1

E&P companies risk millions of dollars in the hope that the revenues they receive from natural gas and oil produced at the wellhead will provide a reasonable return on their investment, after paying for all the costs discussed above (including dry holes).

Delivering Natural Gas from Producing Region to Market

Processing

Natural gas from completed wells within a producing field is delivered through the gas-gathering system to *processing plants,* where separators, dehydrators, membranes, fractionators and other treatment techniques clean and condition the gas for safe and efficient transportation and end-use by consumers. Heavier hydrocarbon gases, primarily ethane, propane and butane (*wet gas*), typically are removed, leaving principally methane or *dry gas*. At atmospheric pressure propane and other wet gases can be liquefied into *condensates* or *natural gas liquids* (NGL). Gas processors and oil refiners market these valuable byproducts as *liquefied petroleum gases* (LPG) for agricultural and rural residential fuel or as feedstocks for the petrochemical industry. However, with the high natural gas prices that have materialized in recent years, some gas processors often find it more economical *not* to remove NGL from the processed gas stream. Nonhydrocarbon impurities such as carbon dioxide, hydrogen sulfide, nitrogen, oxygen and water vapor must, however, be reduced to levels that satisfy specifications for transport through interstate pipelines, which, together with transportation rates, are detailed in a pipeline company's *tariff*. More than 500 gas-processing plants, with a total daily capacity in excess of 68 Bcf, are in operation throughout the nation's oil and gas-producing regions.[77] More and more, these facilities are owned and operated by independent *midstream* companies rather than the *upstream* E&P companies.

Transportation

Conditioned gas that leaves the processing plant via the *tailgate* is delivered to a *receipt point* where it is pressurized for transport to market via buried interstate and intrastate *transmission* pipelines or *trunk lines*, typically 12 to 42 inches in diameter. *Compressor stations* are required at intervals along a pipeline to maintain the high pressures needed to move the gas along. The map in Figure 257 illustrates the extent and complexity of the gas pipeline network that crosses the United States and southern Canada. Large pipelines interconnect with others at more than 1,400 locations so that transporters have the greatest possible flexibility and reliability in matching diverse supplies from producers to the changing demands of gas purchasers.

Construction and operation of interstate pipelines and associated gas-storage sites are governed by the Federal Energy Regulatory Commission (FERC). Intrastate facilities are governed by the respective states.

The pace of pipeline and capacity additions has accelerated since 2005. At a total investment of $15.7 billion, 134 projects were completed in 2007 and 2008—from installing additional compression capacity and extending existing lines, to laying new pipelines. Many new lines involved *looping*, or the construction of a parallel line or doubling of a line over part of its length to increase throughput capacity. Transporters added 1,663 miles of new lines in 2007 with 14.9 Bcfd of capacity additions. Line additions more than doubled in 2008, to 3,893 miles, and capacity additions increased more than threefold, to a most impressive 44.6 Bcfd.[78, 79] Many intrastate system expansions and upgrades were necessary to accommodate rapidly increasing production and optimistic production forecasts from Mid-Continent and northern Gulf Coast shale-gas plays.

The largest project completed in 2008 was the 718-mile western segment (Wyoming to Missouri) of Kinder Morgan's giant $5 billion Rockies Express (REX) pipeline. When the eastern segment is completed in late 2009, REX will transport Rocky Mountain gas 1,679 miles from southern Wyoming all the way to southeastern Ohio (Figure 257). REX, one of the largest single pipeline projects ever undertaken in the Lower 48 States, will have initial capacity of 1.8 Bcfd.

Delivery

Interstate and intrastate transmission pipeline companies deliver about 40 percent of transported gas directly to large-volume *end users*, such as industrial gas consumers and independent power generators. The remainder is delivered by way of the *city gate*, where ownership of the gas changes (*custody transfer*) to *local distribution companies* (LDC), who then deliver the gas to their residential and business customers through their own networks of lower pressure, smaller diameter *distribution lines* and still smaller *laterals*. More than 70 percent of the approximately 1,300 LDCs in the country are owned and operated by municipal governments, and about 20 percent are investor-owned and regulated by state public utilities commissions.[80] Investor-owned LDCs, who serve the greatest number of customers, are responsible for about 92 percent of the total volume of delivered LDC

77. Tobin, James, Phil Shambaugh, and Erin Mastrangelo, 2006, Natural gas processing—The crucial link between natural gas production and its transportation to market: U.S. Dept. of Energy, Energy Information Administration, Office of Oil and Gas, January, 11 p.

78. Gaul, Damien, 2008, Additions to capacity on the U.S. natural gas pipeline network, 2007: U.S. Dept. of Energy, Energy Information Administration, Office of Oil and Gas, July, 14 p.

79. Gaul, Damien, 2009, Expansion of the U.S. natural gas pipeline network—Additions in 2008 and projects through 2011: U.S. Dept. of Energy, Energy Information Administration, Office of Oil and Gas, September, 17 p.

80. Tobin, James, 2008, Distribution of natural gas—The final step in the transmission process: U.S. Dept. of Energy, Energy Information Administration, Office of Oil and Gas, June, 14 p.

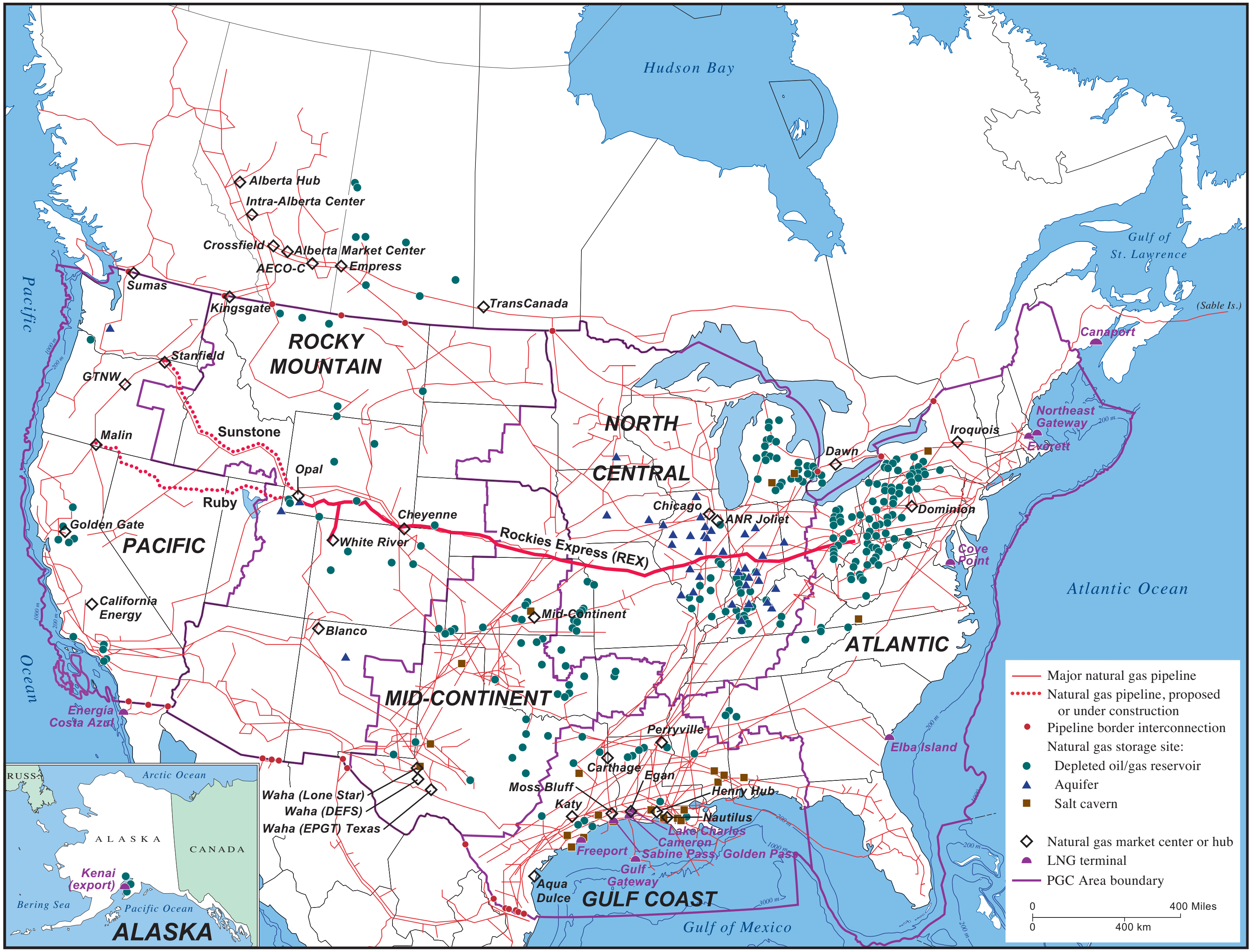


Figure 257. Major natural gas pipelines of the United States, Canada and northern Mexico, showing natural gas storage sites, market centers and LNG terminals. Smaller pipelines and intrastate networks have been omitted for clarity.

gas. The remaining distributors are privately owned (and state-regulated) or operated as nonprofit cooperatives.

Storage

Some of the natural gas transported through the interstate pipeline network is routinely diverted and temporarily placed in pressurized underground *storage fields*. These facilities are designed to deliver gas on short notice (daily and even hourly) to meet surges in consumer demand, such as for heating and power-generation requirements during extremely cold weather, and to offset unexpected curtailments in production or delivery due to pipeline accidents, hurricanes and other severe weather events. Thus they help avoid price spikes. Just as importantly, storage sites help *balance* or equalize the volumes of gas normally contracted to be withdrawn from a pipeline system with the volumes injected. Active storage sites currently number about 400 in thirty states (see Figure 257) and include depleted reservoirs in oil and gas fields (326), aquifers (43) and man-made salt caverns and salt mines (31).[81,82] Gas-storage sites are owned and operated by pipeline companies, LDCs and independent storage developers.

The total volume of gas in a given storage field consists of two components—a larger, relatively permanent volume of *base* gas, which is needed to maintain adequate pressure and deliverability rates, and a smaller cushion of *working gas* that can be withdrawn quickly during times of high demand and later replenished by injection during times of normal demand, a routine practice known as *cycling*. Storage inventories typically are rebuilt following the winter heating season (November 1 to March 31). Individual sites store between 1 Bcf and 50 Bcf of working gas, which can be withdrawn presently at rates up to 1.2 Bcfd.

As a result of expansions and new construction, total demonstrated peak working-gas capacity rose in 2008 and early 2009 to 3,889 Bcf.[83] The total volume of working gas available at any given time, in relation to historical maxima and the running five-year average tracked by the EIA, strongly influences the price of natural gas that is set in futures contracts traded on the commodity market. With the higher output of natural gas in 2008, together with lower demand and prices due to the recession and to moderated temperatures in some areas, working-gas volumes reached an historical high of 3,565 Bcf.

Periodically, a transporter or storage operator may hold an *open season*, a period of time, usually several weeks, during which existing and prospective customers and marketers may bid, on an equal and often nonbinding basis, for a specified amount of available or planned transport and/or storage capacity and other services.

Commerce

Where a number of large pipelines interconnect to facilitate access to multiple regions of supply is termed a *market center* or *hub*. Located at strategic points on the pipeline grid (Figure 257), market centers offer a variety of essential transportation and administrative services to shippers, purchasers and marketers, not only storage and compression but also short-term receipt/delivery balancing, volume aggregation and title transfer.[84]

Hub configurations vary—some are associated with one pipeline system while others operate through shorter bidirectional (flowing both directions) *header* systems connected to other pipelines or to storage sites and gas processing plants.

The Henry Hub in southern Louisiana is the designated delivery point for natural gas futures contracts, which are traded on the New York Mercantile Exchange. Accordingly, Henry Hub is the market center to which gas prices at other hubs are compared daily. How much the short-term cash or *spot* price for gas (in \$/Mcf or \$/MMBtu) varies with respect to the Henry Hub futures price is referred to as the *basis differential*. In gas-supply regions that may have less outbound transport capacity or access to fewer markets, the differential can, in effect, be a relative price disadvantage under which producers, transporters and marketers must make decisions regarding sales, trades and other business.

The Integrated Delivery System

In total then, 468,000 producing gas wells, 500 gas-processing plants, 210 gas pipeline systems consisting of 300,000 miles of interstate and intrastate transmission pipelines, more than 1 million miles of gas-gathering lines, 1,400 compressor stations, 400 storage sites, 50 import/export border pipeline interconnections, eight LNG import and regasification terminals (including two offshore), 28 market centers and more than 1,300 local distribution companies comprise the vast, complex physical infrastructure that provides natural gas service to consumers in all fifty states.

This completes the complex process "from reservoir to burner tip."

81. Tobin, James, 2006, U.S. underground natural gas storage developments—1998–2005: U.S. Dept. of Energy, Energy Information Administration, Office of Oil and Gas, October, 16 p.
82. These are separate from the approximately 100 aboveground facilities that store relatively small volumes (<1 Bcf) of liquefied natural gas (LNG) for local distribution. Many of these are located in nonproducing regions, such as New England, the Atlantic Seaboard and the southeastern states, where underground storage is infeasible.
83. LaRose, Angelina, 2009, Estimates of peak underground working gas storage capacity in the United States, 2009 update: U.S. Dept. of Energy, Energy Information Administration, Office of Oil and Gas, August, 5 p.

How Natural Gas is Used

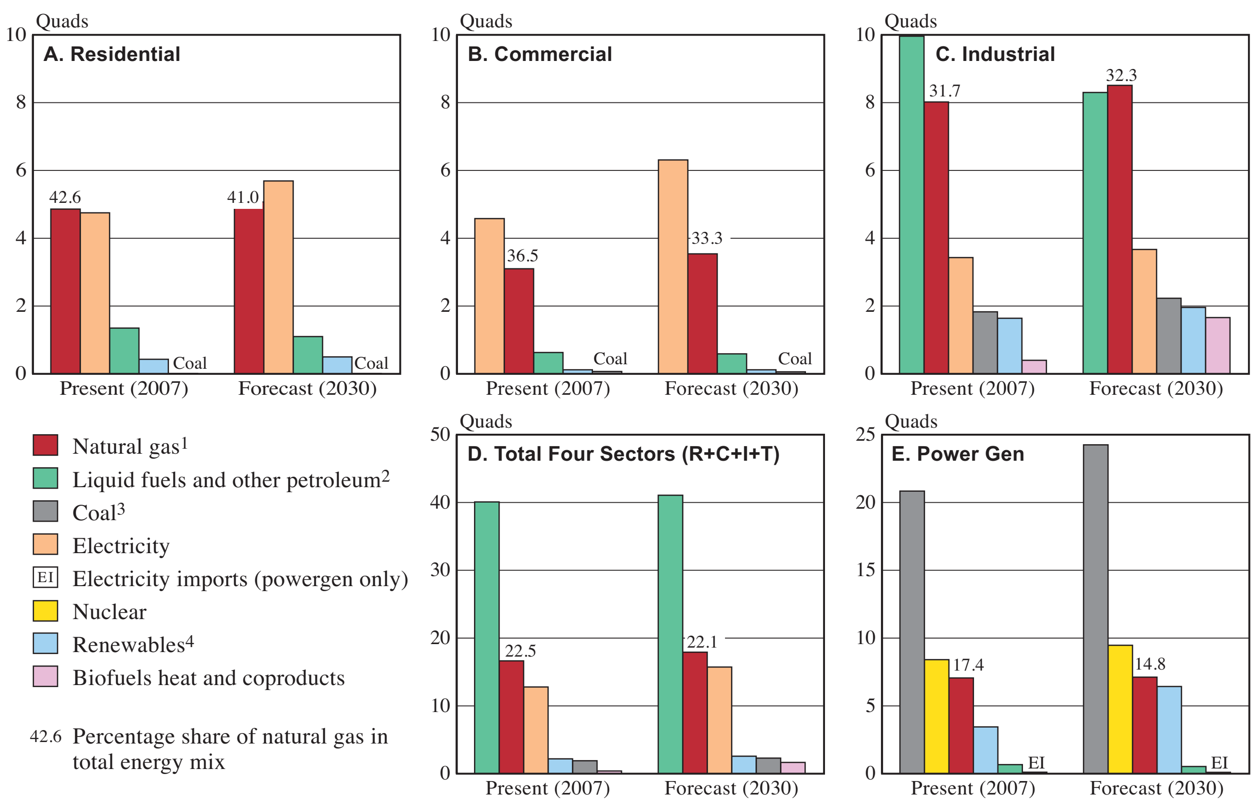
Natural gas finds many important uses among the nation's four principal energy consumer sectors—residential, commercial, industrial and transportation—and in electric power generation. According to data from EIA, in 2008, 92 percent of the 23.2 Tcf of natural gas consumed in the U.S. was delivered to these consumers as follows:[71]

Consumer Sector	Volume (Bcf)	Proportion of Total
Residential	4,866	20.9%
Commercial	3,122	13.4%
Industrial	6,652	28.6%
Electric Power	6,661	28.7%
Transportation (vehicle use)	30	0.1%
Total Deliveries	21,331	91.8%
Lease and plant fuel, pipeline and distribution use	1,913	8.2%
Total Consumption	23,243	100.0%

EIA's latest projections for energy demand over the next two decades[85] indicate that natural gas consumption (on an equivalent Btu basis [see sidebar, *Consumer Gas Facts*]) will rise in all four consumer sectors, as illustrated in Figure 258. The average rate of annual growth in gas demand from 2007 to 2030 (+0.3 percent), however, is forecasted to be less than other energy sources, namely electricity in the residential and commercial sectors, and coal, biofuels and renewables in the industrial sector. Consequently, although the volumes of gas consumed will increase, the proportional share of natural gas in the overall energy mix by 2030 (Figure 258D) is forecasted to decline slightly. These projections change from year to year, however.

84. Tobin, James, 2009, Natural gas market centers—A 2008 update: U.S. Dept. of Energy, Energy Information Administration, Office of Oil and Gas, April, 14 p.

85. Conti, J.J., and others, compilers, 2009, Annual Energy Outlook 2009, with Projections to 2030: U.S. Dept. of Energy, Energy Information Administration, Office of Integrated Analysis and Forecasting, Rept. DOE/EIA-0383(2009), March, 221 p. Available online at http://www.eia.doe.gov/oiaf/aeo/.



1. Includes industrial sector natural gas for lease and plant fuel.
2. Includes LPG, motor gasoline and ethanol blends, kerosene, distillate and residual fuel oils, petroleum feedstock (industrial), jet fuel and miscellaneous petroleum and petroleum-derived products.
3. Includes industrial sector metallurgical coal, CTL heat and power, and minor coal-coke imports.
4. Primarily hydroelectric for power generation. For all sectors in 2007: hydroelectric (36.8%), biomass and biofuels (48.7%), geothermal (4.6%), municipal waste (4.9%), wind (4.8%), solar (0.2%).

Figure 258. The role of natural gas in meeting domestic energy demand, by primary consumer sector, a comparison of the mix of principal energy supplies (in quads) for 2007 with that forecasted at 2030. A. Residential. B. Commercial. C. Industrial. D. Total of four sectors (residential, commercial, industrial, transportation). E. Power generation. Data from EIA *Annual Energy Outlook 2009*.

Consumer Gas Facts

In the United States, natural gas, like other forms of heat energy, is commonly measured in terms of its heat content, expressed in traditional "British thermal units," or Btu. One Btu is the quantity of heat needed to raise the temperature of one pound of water by one Fahrenheit degree (1 F°) at atmospheric pressure (14.7 psi). One cubic foot of natural gas contains about 1,027 Btu of heat energy.

Natural gas normally is sold from the wellhead in the production field to purchasers in standard volume measurements of "thousand cubic feet" (Mcf). Consumers' utility bills may report gas consumption in hundred cubic feet (ccf) or in "therms" (th). One therm equals 100,000 Btu. If, for example, your monthly gas bill reported 80 th of gas usage, volumetrically you consumed:

$$80 \text{ th} \times \frac{100{,}000 \text{ Btu}}{1 \text{ th}} \times \frac{1 \text{ cf of gas}}{1{,}027 \text{ Btu}} = 7{,}790 \text{ cf or } 7.79 \text{ Mcf of gas}$$

Similarly, natural gas transmission companies in the U.S. commonly express their pipeline capacities and throughput in terms of heat content rather than volume, expressed in "dekatherms" per day.

Residential Consumers

Natural gas increasingly is the fuel of choice for heating in today's homes. Consumers realize that not only is natural gas the cleanest of all fossil fuels and the best energy choice for the environment, but it's also America's best energy value. On an average $/MMBtu (million Btu) basis, natural gas for residential use in 2007 was substantially more affordable ($12.69) than either fuel oil ($19.66) or LPG ($24.98) and less than one-half the cost of electricity ($31.19).[85]

Residential natural gas is used primarily for space heating and water heating, in separate or combination systems of high-efficiency direct-vent furnaces and boilers. Other household uses include kitchen ranges, barbecue grills, fireplaces, spa and patio heaters, and stacked clothes washers and dryers.

Because of substantially lower operating costs for gas appliances, consumers have, since the 1960s, preferred natural gas for home heating over all other fuel sources, including electricity. The number of housing units heating with gas has climbed from 35 million (1970) to 56.7 million in 2007.[71]

By 2020, natural gas for residential purposes is expected to increase in nearly all geographic and climatic regions of the Lower 48 States, more so in the West and Northwest as a result of population shifts and a trend toward building larger homes.[86] Per-capita consumption will lag the total growth rate because of improved energy efficiencies in homes and appliances.

Commercial Consumers

Over 5.3 million consumers in the commercial sector use natural gas for space heating and cooling in office buildings, retail and service establishments, malls, hospitals, schools and colleges, warehouses, motels and hotels, and for cooking in all types of restaurants. The two basic commercial cooling applications are space conditioning and refrigeration. Individual applications range in size from three tons (light commercial and residential) to several thousand tons (district heating and cooling loop).

Office buildings: About 59 percent of office buildings use natural gas as an energy source. Many buildings are now reaching the age where simple changeouts to new, more efficient heating and cooling systems can lower operational costs, an important consideration where cents per square foot can "make or break" a lease renewal deal.

Retail: Nationwide, 58 percent of retail buildings are supplied with natural gas for use in space heating, water heating, cooling and cooking.

Health care: Natural gas is estimated to be an energy source in about half of hospitals nationwide. Hospitals' strong electric and thermal load profiles make them excellent candidates for cogeneration and gas cooling applications.

Motels and hotels: Seventy-three percent of lodging facilities use natural gas as an energy source, and 50 percent employ it for space heating. The major reasons include lower life-cycle costs, humidity control and a desire for energy-efficient structures.

Food service: Natural gas is used in 78 percent of restaurant facilities. One survey indicated that 97 percent of chefs prefer to cook with natural gas because of precision in temperature control, speed of cooking, low operating cost and high efficiency.

On an average $/MMBtu basis, natural gas for commercial use in 2007 was slightly more expensive ($10.99) than residual

86. Wilkinson, Paul, Chris McGill, Kevin Petak, and Bruce Henning, 2005, Natural Gas Outlook to 2020—The U.S. Natural Gas Market, Outlook and Options for the Future: Washington, D.C., American Gas Foundation, February, 113 p. Available from the American Gas Association website, http://www.aga.org/Template.cfm?Section=Non-AGA_Studies_Forecasts_Stats&template=/ContentManagement/ContentDisplay.cfm&ContentID=15587.

fuel oil ($10.21) but less than distillate fuel oil ($16.05) and well less than one-half the cost of LPG ($23.04) and electricity ($28.07).[85]

Industrial Consumers

Industry is the largest gas-consuming sector because of the inherent energy-intensive nature of many heavy manufacturing and processing operations and the fact that natural gas is the essential feedstock for so much of our vital chemical production, especially ammonia fertilizer for agriculture. Indeed, natural gas for bulk chemicals production accounted for 27 percent of industrial gas consumption in 2005.[87] Another 60 percent was consumed for oil refining, mining, food, paper and steel manufacturing, construction and metals fabrication. Other important uses include glass and plastics manufacturing, aluminum smelting, pulp processing and paper manufacturing, agriculture and fuel for ethanol distillation. In addition to its use for boiler fuel and process heat in these industries, natural gas finds application in waste treatment and incineration, drying and dehumidification, heating and cooling, and industrial power cogeneration, including standby generation capacity. Because of federal clean-air regulations, natural gas applications that reduce nitrous and sulfurous oxide emissions have very strong potential in the industrial market.

On an average $/MMBtu basis, the price of natural gas used by 205,000 industrial consumers in 2007 was less expensive ($7.52) than electricity ($18.63) and all other major fuels ($10.49–$23.38) except coal ($3.61).[85]

Power Generation

Through the 1990s, natural gas had become the preferred fuel for generating electricity at "peaker" plants, power plants that are smaller in capacity than the utilities' *base-load* plants (typically coal, nuclear and hydro). Peakers can be brought on line at full capacity quickly to help meet peak electricity demands as well as to satisfy normal demands during scheduled and unscheduled shutdowns at base-load plants. Because of ever-increasing demands on base-load stations, many peakers now run longer than just during peak hours. Most peakers are operated by *independent power producers* (IPPs). In addition, because of its high reliability, natural gas is becoming important as a backup fuel for alternative and renewable energy projects.

Natural gas has accounted for a steadily increasing share of total net electricity generated (in kilowatt-hours, kWh) from fossil fuels in the power generation sector—from 13 percent in 1988 to 28 percent in 2007 and 2008. In the last two years natural gas accounted for 20 percent of the net electricity generated from all energy sources (fossil fuels, nuclear, hydro and other renewables).[71]

Of the total new generation capacity added between 1999 and 2002, 96 percent was natural gas fired. In its projection to 2030,[85] EIA forecasts that natural gas plants will account for more than one-half (53 percent) of all new generation capacity additions—137 gigawatts (GW, or 1,000 MW) out of 259 GW net after retirement of older power plants.

Utilities and IPPs base their decisions regarding the choice of fuel for future capacity additions on such factors as electricity demand growth; the need to replace inefficient plants; capital, variable and transmission costs; operating efficiencies; fuel prices; emissions constraints; and availability of federal tax credits for certain technologies. Compared to coal, nuclear and wind, natural gas-fired plants have substantially lower capital costs but considerably higher variable costs, fuel expenditures in particular, which constitute the largest component (~75 percent) of total plant costs. Thus, while coal, nuclear and wind plants are highly sensitive to construction costs, which are escalating over the near term, gas plant costs are more sensitive to natural gas prices, which are tied closely to oil prices and to domestic gas production levels, which are now rising.

In its last two projections, EIA has scaled back its growth forecast for natural gas consumption in power generation. EIA now projects a +3 percent average annual growth rate for gas consumption from 2007 (7.06 quadrillion Btu, or "quads") to 2025 (7.59 quads) but only a 0.3 percent overall increase by 2030 (7.12 quads). Although the volume of gas consumed annually will increase, its share of total end-use generation capacity (kWh) is projected to decline mostly in deference to renewables, as shown in Figure 258E.[85] Again, however, EIA's projections change from year to year.

Combined Heat and Power (CHP) Generation

CHP generation includes two high-efficiency technologies for producing electricity—natural gas combined-cycle systems and cogeneration turbine systems. Both systems capture and reuse waste heat that normally is lost. A combined-cycle plant uses waste heat from gas combustion (in a gas turbine or a battery of gas engines) to produce additional electricity by heating water to make steam (to drive a steam turbine). A cogeneration system, on the other hand, uses the captured thermal energy to generate additional electricity, provide space heating or fulfill other energy needs of a building, factory, park or campus. In most electric power plants, the waste heat from fuel combustion is lost, resulting in substantially lower operating efficiencies. Combined-cycle systems account for nearly 80 percent of installed CHP capacity.

87. Energy Information Administration, 2007, Annual Energy Outlook 2007, with Projections to 2030: U.S. Dept. of Energy, Energy Information Administration, Office of Integrated Analysis and Forecasting, Rept. DOE/EIA–0383 (2007), February, 229 p.

Combined-Cycle Generation. Natural gas-fueled combined-cycle systems offer attractive economic, environmental and operating characteristics. For example, combined-cycle gas turbine plants generate electricity more efficiently than conventional fossil-fuel plants, with efficiencies approaching 60 percent, compared with 30 to 35 percent for typical boiler units.

In addition, gas-fueled combined-cycle units offer lower construction and maintenance costs, higher operating reliability and shorter construction time frames. Furthermore, compared to similarly sized coal units equipped with pollution-control equipment, combined-cycle units produce no solid wastes, less than 1 percent of the sulfur oxides (SO_x) and particulate matter, and about 85 percent less nitrogen oxides (NO_x).

Cogeneration. Gas-fired cogeneration or "cogen" systems offer the same advantages as combined-cycle generation, in terms of capital and operating costs, efficiencies and emissions. Large coal-fired cogeneration systems average from one-and-one-third to more than three times the capital costs of natural gas-based systems because they require pollution-control equipment, greater land requirements for the plant and fuel stockpiling, expensive fuel-handling equipment, greater boiler maintenance and more personnel.

Many commercial and industrial facilities can take advantage of natural gas cogen systems because of their highly variable requirements for heat and electricity. Cogen systems are available in sizes from as small as 2.2 kilowatts to as large as several hundred megawatts. Natural gas-fueled cogeneration is being successfully applied in the pulp and paper, pharmaceutical, food processing, textile, oil refining, fertilizer and other petrochemical industries, as well as in hospitals, universities, hotels, computer centers and other commercial facilities.

Electricity generation and thermal output (Btu basis) from CHP systems have in recent years declined in the powergen sector as well as in the commercial and industrial sectors, the latter two reflecting overall declines both in consumption of combustible fuels for powergen and in total electricity output. EIA forecasts that CHP electricity output will continue to decline, by 0.9 percent annually, to 2030 and that consumption of natural gas, while still fueling 75 percent of total CHP generation, will decline 0.7 percent annually.[85]

Transportation

Natural gas is quickly gaining recognition as the most environmentally acceptable and economic alternative fuel for America's cars, trucks and buses for the near term. About 120,000 natural gas vehicles (NGVs) in the United States operate safely, cleanly, efficiently and economically. California, Texas and Arizona are home to one-half of all NGVs in use in the U.S. and together accounted for nearly two-thirds of the natural gas consumed in NGVs in 2007.[88]

The estimated volume of natural gas consumed by NGVs in the U.S. has doubled since 2002, from 15 Bcf to 30 Bcf in 2008.[71] However, the EIA estimates that the total number of NGVs (CNG and LNG) in use has declined from a high of 123,500 in 2002 to 117,170 in 2007.[88] With the availability now of a dedicated natural gas-fueled vehicle from a major auto manufacturer and the increasing public awareness of the benefits of NGVs in discussions about energy policy, the number of new and converted natural gas vehicles should begin to increase.

Compressed natural gas (CNG) has distinct advantages over traditional transportation fuels. It burns more cleanly; it costs less on a gasoline-gallon-equivalent basis; it requires less space for storage; and it has a proven safety record. Furthermore, the Energy Policy Act of 2005 has made federal tax credits available to operators of manufactured NGVs and petroleum-fueled vehicles that have been retrofitted or repowered with EPA- or CARB (California Air Resources Board)-certified natural gas engines or conversion systems. *Liquefied natural gas* (LNG, but excluding LPG) also is used in NGVs to a smaller extent, primarily in heavy-duty vehicles.

Natural gas is especially well suited for the nation's 11.5 million government and corporate fleet vehicles, many of which return to a central location each night for refueling. According to NGVAmerica, although more than 60 percent of CNG vehicles presently are classified as light-duty, CNG applications more and more are directed toward medium- and heavy-duty vehicles, such as transit buses, school buses, utility vehicles, sanitation trucks and off-road industrial and aviation vehicles, which typically have high fuel-consumption rates and, like fleets, can take advantage of centrally located refueling docks.[89]

Compared to the rest of the world, where about five million NGVs operate, expanded use of NGVs in America has been constrained in large part by the limited, but growing, number of refueling stations, which number about 1,100 but only about one-half of which currently sell to the public. However, with the availability now of home refueling units, which also qualify for federal and some state tax credits, a resurgence in car and light-duty NGV demand may be forthcoming.

88. Energy Information Administration, 2009, Alternatives to traditional transportation fuels, 2007: Energy Information Administration, April. Data for 2003–07 available at http://www.eia.doe.gov/cneaf/alternate/page/atftables/afv_atf.html#supplied.
89. Yborra, Stephe, 2006, Taking a second look at the natural gas vehicle: American Gas Magazine [American Gas Association], August-September. Available from American Gas Association website, http://www.aga.org/Content/ContentGroups/American_Gas_Magazine1/August_September_2006/Taking_a_Fresh_Look_at_NGVs.htm.

Important technical advancements continue to be made by the American Gas Association, Gas Technology Institute, DOE and other groups in bringing more fuel-efficient NGVs into the marketplace.

Natural Gas Supply Outlook

Demand for natural gas for all uses in the United States will continue to grow during the next quarter century, from about 23 Tcf in 2007 to about 24.36 Tcf by 2030, or about 0.7 percent annually, according to EIA's latest forecast.[85] Other organizations project consumption levels at 2030 ranging from 21 Tcf to 29 Tcf. The U.S. has abundant natural gas resources that can be targeted for exploration and development drilling to help meet these future energy needs. Because natural gas is the cleanest burning fossil fuel, it is playing an increasingly prominent role in helping to attain national goals of cleaner air, energy security and a more competitive and stable economy.

The Role of Reserves

How well the natural gas industry can sustain itself and help achieve these ends depends on its ability to *prove up* enough new gas *reserves* each year—through new field and new reservoir discoveries and field extensions—to replace the volume of gas produced for consumption. To prove up reserves on a continuing basis, industry must have a substantial *potential resource base* at its disposal, as well as access to those resources and the materials, personnel and technologies needed to explore, evaluate and develop them. (See the chapter, *Methodology of the Potential Gas Committee*, for further discussion of proved reserves and resources.)

Our domestic reserves situation suffered during the early to middle 1980s as a result of the so-called "gas bubble," in actuality an abnormal surplus of production capacity rather than an excess of gas itself. This unusual circumstance effected dramatic declines in drilling activity, production and reserves additions. The situation improved thereafter, largely through elimination of the federal government's disastrous attempts to control natural gas prices and restrict how gas was used. With disincentives removed, exploration rebounded. Although new discoveries continued to be made throughout this period, not until 1994 did the year-to-year change in proved reserves finally move into positive territory.

Industry's success with reserves replacement can be seen by examining changes on a ten-year basis. Industry as a whole first achieved consistent 100 percent replacement of production (dry gas) with reserves additions (including adjustments) during the decade 1993–2002, resulting in a net (positive) balance of 22 Tcf (the sum of annual changes in reserves from 19993 through 2002).[90] Both the replacement ratio and balance have increased since then. For the decade 1999–2008, industry replaced 126 percent of production, resulting in a balance of +80.6 Tcf. The replacement ratio for year 2007 reached a record 229 percent. Less spectacularly, reserves additions in 2007 and 2008 came primarily from extensions of existing fields (a record 27 Tcf in 2007), rather than through new discoveries from grass-roots exploration efforts, which were more evident during the late 1970s and the 1990s. Nevertheless, EIA's proved reserves for year-end 2008, 244.6 Tcf, is the highest reported since 1973.

Proved reserves then become the basis for determining our *future supply* of natural gas. To this value we add the Potential Gas Committee's assessment of potential resources—that is, remaining *technically recoverable* natural gas resources, traditional and coalbed, 1,673 Tcf and 163 Tcf, respectively (see Table 3 in the Executive Summary of this report). For year-end 2008 (using EIA's 2007 value for reserves), our future gas supply is estimated to exceed 2,074 Tcf.

As natural gas demand increases and as technology continues to improve our chances for discovery as well as recovery rates, we expect that the industry will be able to prove up more new reserves than are produced each year so as to maintain a desirable positive balance. The Potential Gas Committee accomplishes its role by continuing to provide, on a regular basis and as accurately as possible, estimates of the potential resource base from which proved reserves and production ultimately derive.

Supplemental Natural Gas Supplies

Besides drawing gas from storage on a seasonal basis, the natural gas industry can respond relatively quickly to increases in demand in two other ways—by tapping traditional sources and by developing near-term supplemental sources. This capability is found in four supply categories, each with its own limitations:

1. *Domestic—Nonproducing reserves*. Substantial gas reserves available in the Lower 48 States are not being produced, not for lack of demand but because of operational constraints and delays. These factors include the time to install production facilities and connect new wells to pipelines, particularly in the remote deepwater Gulf of Mexico; time required to drill development wells and complete *workovers* of underperforming wells; the practice of extracting as much gas as possible from producing reservoirs before tapping other known reservoirs not presently open to production (*behind-*

90. Energy Information Administration, 2009, U.S. crude oil, natural gas, and natural gas liquids reserves—2007 Annual report: U.S. Dept. of Energy, Energy Information Administration, Office of Oil and Gas, Rept. DOE/EIA–0216(2007), February, 132 p.

pipe or *bypassed* reserves); and shut-in or loss of production capacity due to wildfires, hurricanes and other severe weather events. Nonoperational factors, such as volatility of gas prices and constantly fluctuating volumes of gas in storage, also contribute to the wide year-to-year variability in the volume of reserves classified as nonproducing. For year-end 2008 EIA reported 85.5 Tcf of nonproducing reserves,[91] of which 78.9 Tcf (92 percent) was nonassociated gas. Of the total, 7 Tcf (8.3 percent) are located in federal and state waters of the Gulf of Mexico. By PGC area, approximately 23 Tcf (27 percent) of these reserves lie within the onshore Gulf Coast, 29.8 Tcf (35 percent) in the Rocky Mountains, and 21 Tcf (25 percent) in the Mid-Continent.

2. *Domestic—Accelerated infill drilling*. In the early 1980s, gas deliverability increased as a result of extensive new drilling in known fields, that is, adding new wells to enhance overall recovery of available gas. This is accomplished in two ways. First, development wells can be added to the undeveloped area of a known field at a *well spacing* (in acres) that a state oil and gas commission may authorize for a particular producing pool. Standard well-spacing units typically are 80 acres, 160 acres or 320 acres (0.5 mi^2), that is, one well is permitted to be drilled on 80, 160 or 320 acres. Second, under certain circumstances, an operator may petition the commission for *downspacing*, an exemption to drill wells at a density greater than that permitted at the standard spacing unit, such as four wells on a 160-acre unit, resulting in an effective well spacing of 40 acres. Exemptions have been granted for 20 acres and even 10 acres. Spacing exemptions can be justified when geologic conditions of the producing reservoir are such that wells at the standard spacing are situated too far apart to optimally drain the maximum volume of available gas or oil. For example, sandstone reservoirs may exhibit extremely low permeabilities and/or complex geometries that inhibit the flow of gas, or an area may be so complexly faulted that the reservoirs have become “compartmentalized” and lack the hydrodynamic communication with one another that could otherwise facilitate production at a standard well spacing. Many natural gas fields have potential for accelerated infill drilling to increase production capability. However, infilling or downspacing in certain areas, while boosting field output locally, may not offset the overall natural decline in productivity that commonly characterizes a mature producing basin.

3. *Imports—Canadian pipeline gas*. Importing natural gas via pipelines is the principal means by which the U.S. meets the shortfall each year between domestic production and domestic consumption, which has widened since the late 1980s, as shown in Figure 259A. U.S. companies

91. Energy Information Administration, 2009, U.S. crude oil, natural gas, and natural gas liquids reserves—2008: U.S. Dept. of Energy, Energy Information Administration, Office of Oil and Gas, Rept. DOE/EIA–0216(2007), October, unpaginated text, 23 figs., 13 tables.

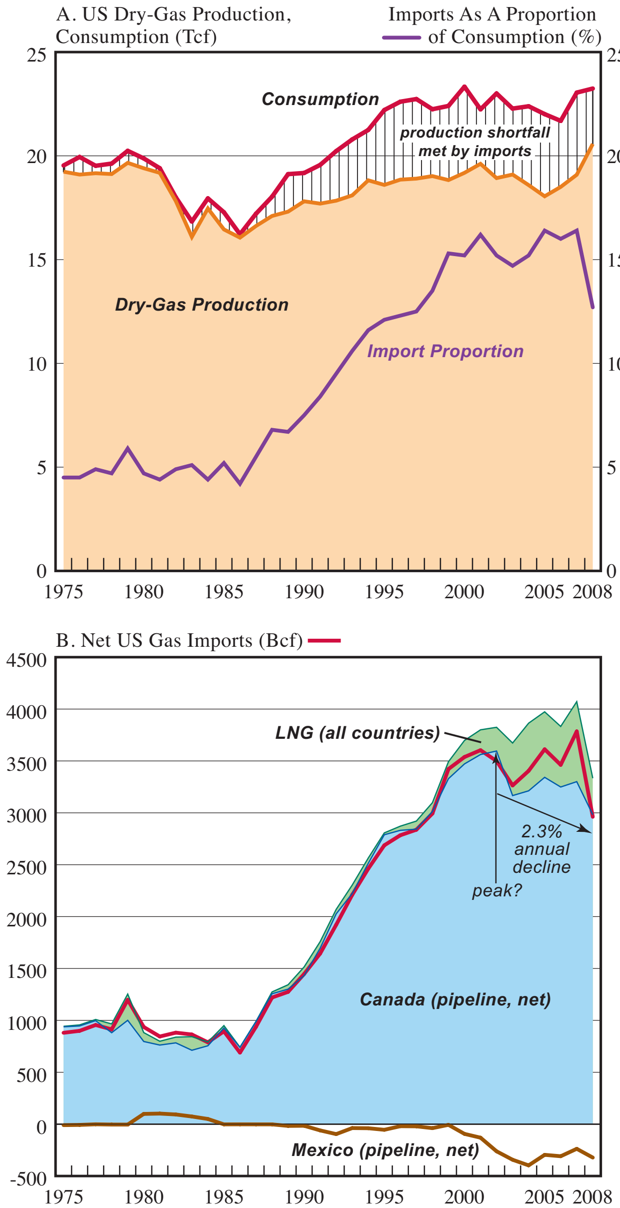


Figure 259. A. U.S. dry-gas production and consumption, 1975–2008, showing proportion of consumption attributable to imports. B. U.S. net imports of natural gas, 1975–2008. Data from EIA *Annual Energy Review 2008*.

contract with Canadian producers and marketers to import substantial volumes of Canadian gas, principally from the Western Canadian Sedimentary Basin of Alberta, British Columbia and Saskatchewan (Figure 257) but also from maritime Canada (offshore Nova Scotia). Net imports in 2007 totaled approximately 3,300 Bcf, or 9 Bcfd, which is about the average volume imported annually since 1999 (Figure 259B).[71] Net imports for 2008 dropped noticeably, to 2,982 Bcf (8.2 Bcfd), partly the results of lower Canadian output and higher U.S. production.

The statistics and production trends in Canada suggest that we cannot assume reliability of imports at the recent average level for the long term. In fact, Canadian pipeline exports to the U.S. already may have peaked, at 3,600 Bcf in 2002, a reflection of the overall drop in Canada's total gas output since 2001. The mature conventional-gas fields of western Canada are experiencing the same natural declines in productivity as those in the U.S. Like the U.S., Canada does possess substantial resources of unconventional natural gas in coalbeds, tight sandstones and shales, but analysts disagree over whether accelerated development of those resources will materially slow the decline in total gas productivity. With domestic demand for natural gas within Canada on the rise—for Alberta oil sands development, in particular—and uncertainties about future development of gas discoveries in the country's remote northwest and Atlantic offshore, future U.S. imports at historical levels certainly are not assured. EIA and Canadian forecasters expect Canadian exports to drop 3 percent or more annually over at least the next five years. Imports already have declined an average of 2.3 percent annually since 2002 (Figure 259B).

4. *Imports—Liquefied natural gas*. The balance of our imports each year arrives as liquefied natural gas, or LNG, from four to as many as eight foreign countries. Algeria has been the most consistent exporter since LNG imports commenced in 1970, but since 2000 most of our LNG by volume has come from Trinidad and Tobago. Other sources in 2007 and 2008 included Egypt, Nigeria, Qatar and Norway. Imports reached an historical peak of 771 Bcf (2.1 Bcfd) in 2007 but fell by nearly one-half in 2008, to 352 Bcf (<1 Bcfd) (Figure 259B).[71]

Eight LNG import terminals presently are in operation—six on the U.S. mainland (portside) and two offshore (Gulf of Mexico, Massachusetts Bay), shown on Figure 257. Three (Northeast Gateway, Freeport and Sabine Pass) were commissioned in 2008. As a result of the new terminals and recent expansions at others, total regasification and sendout capacity at year-end 2008 stood at about 10.2 Bcfd,[92] obviously more than sufficient to accommodate import levels to date.

Potentially problematic is the eventuality that the industry could overbuild itself—that is, sendout capacity would consistently exceed import volumes by a large margin. This undesirable outcome would result in underutilized capacity at most facilities or even suspension of operations altogether at others, thereby marginalizing LNG imports to the detriment of our overall supply security. Consider that four new terminals now under construction and scheduled for startup by 2010–11 will add another 4.7 Bcfd of capacity, and six others in progress together would, if finished, add 8 Bcfd, not to mention 2.25 Bcfd of new expansions that have been approved but not yet completed.[92] If all projects were to move toward completion, total near-term regasification capacity could total 25 Bcfd. Compared to the present domestic consumption of 63 Bcfd and total net imports of 9 to 10 Bcfd, this level of import capability would seem excessive even for a future high-demand, low-cost projection. Furthermore, two new LNG facilities outside our borders, in New Brunswick and Baja California, also will supply gas to U.S. markets via cross-border pipelines, although in the latter case the U.S. has exported considerably more gas (≤1 Bcfd) to Mexico than it has imported in the last decade.

Further complicating this scenario is the fate of a number of other proposed terminals, several of which have secured some level of interim approval from either FERC, the U.S. Maritime Administration or the U.S. Coast Guard. Situated at "brownfield" and "greenfield" sites on the Atlantic, Gulf and Pacific coasts, only a small fraction of these projects now seem likely ever to secure full approval, and even fewer, if any, ultimately will be built because of mounting "pushback." Although developers themselves have canceled or shelved several projects, most others have become stalled due to drawn-out local hearings, demands for additional environmental studies and safety assessments, petitions to Congress and federal agencies to block approval, litigation against developers, and enactment of new local regulations intended to circumvent FERC's vested authority for terminal site approval by restricting ship movements and prohibiting terminal and berth construction, directly or indirectly.

Given the long-term, capital-intensive nature of LNG facilities, developers face difficult decisions in committing to such projects and must therefore carefully evaluate projections for gas prices and domestic demand (including emerging new markets for gas), certainly challenging tasks in light of the current recessionary environment and alternative-energy movement. No less challenging to assess are the timing of and extent to which new domestic gas sources, namely unconventional (shale) gas and Alaska North Slope gas, will be developed to offset the chronic production shortfall, in turn affecting the levels of all gas imports. A novel strategy that may provide some cushion of safety against LNG capacity underutilization was proposed recently by two terminal operators who have petitioned the Department of Energy to allow them to store and *re-export* offloaded LNG to other destinations when conditions warrant.

Even if LNG developers avoid overbuilding and maintain profitability at whatever capacity level may materialize, they have, however, no assurance that foreign supplies will be available when needed or in the quantities desired. Now that a highly competitive international market for LNG is evolving, the U.S. must, in effect, compete with a growing list of other countries, mainly in Asia and Europe, who seek the same benefits of natural gas that we enjoy but who themselves produce little or none domestically. For them,

92. True, W.R., compiler, 2008, LNG world trade 2008: Oil & Gas Journal, December, poster supplement.

LNG is a necessary and desirable alternative even at comparatively high prices.

Other Supplemental Supplies—Two other domestic sources of gas energy hold limited potential for the future—biomass and urban landfills. Although both are, in a tenuous context, commonly considered *renewable*, their development has been hampered by market demand, economics, location and logistical constraints, variability in feedstock availability and gas yield, and solid residue and byproduct disposal. Moreover, before either can be beneficially used, biomass gas and landfill gas usually require some type of conditioning to remove a portion of the undesirable gases, which are vented. In some cases, power generators and end-use equipment also must be modified to accommodate a leaner fuel.

Biomass includes a variety of terrestrial and aquatic plants, including algae, that many hope in the long term can be cultivated on a large scale and harvested specifically for energy conversion. For now, however, biomass feedstock is recoverable in only limited quantities as wastes and residues from agricultural, forestry and industrial operations. Most biomass (wood) is simply combusted in low-tech fashion to generate heat and/or steam for electricity. Conversion of wood, grass and other types of biomass to gas energy requires more sophisticated technologies, such as thermochemical and plasma gasifiers and anaerobic digesters. Biomass gas (methane) for small-scale, onsite power applications also is generated from livestock manure and from municipal solid wastes and wastewater. Expansion of biomass gas production will require new research in genetic engineering to enhance crop yield and disease resistance, as well as improvements in cultivation and harvesting practices, transportation and handling, gas-conversion and residue processing and disposal technologies and, of course, enormous tracts of arable land, large supplies of irrigation and process water and an accommodating climate.

According to the Environmental Protection Agency (EPA), the number of projects recovering and using methane extracted from municipal landfills has risen from 400 in 2006 to 496 as of July 2009. Landfill-gas (LFG) projects, now operational in 45 states, have resulted in incremental power generation capacity of 1,537 MW and 277 MMscfd of gas production for various commercial, industrial (including cogen) and municipal direct-use applications.[93, 94] This subquality gas—about 50 percent methane and 50 percent carbon dioxide in composition—would otherwise have been flared where emissions were sufficient to do so. EPA estimates that about 525 other candidate landfills across the country have a total gas-recovery potential of 550 to 620 MMscfd and incremental powergen capacity of 1,180 MW. Although no more "renewable" or "green" than "natural" natural gas accumulations, many new LFG projects are subsidized through various federal renewable-energy tax credits and production incentives, and some are further enabled through state and local grants.

A Last Word

Continued development of the nation's natural gas supply will depend in large part on new and improved technologies, access, and the economics of production, processing, transportation and delivery. Given the magnitude and diversity of our domestic resource base, onshore and offshore, as demonstrated by the Potential Gas Committee, natural gas should be available for beneficial use far into this century, not as some "bridge" fuel to an ill-defined energy future but as a solid and dependable cornerstone of the nation's energy foundation and security.

93. Environmental Protection Agency, 2009, An overview of landfill gas energy in the United States: Environmental Protection Agency, Landfill Methane Outreach Program, 34 p. Available at http://www.epa.gov/landfill/overview.htm.
94. Environmental Protection Agency, 2009, Landfill gas energy projects and candidate landfills: U.S. Environmental Protection Agency, Landfill Methane Outreach Program, July.