# 1. Overview

Natural gas use in the United States has shown substantial gains during the past decade, returning to the upward growth trend experienced prior to 1972 when consumption peaked at 22.1 trillion cubic feet (Tcf) (Figure 1). In 1996 and 1997, the Nation again consumed about 22.0 Tcf of natural gas, close to the 1972 record level. For the past 25 years, however, the development and structure of the industry contrasted sharply with the industry prior to 1972. From 1950 to 1972, natural gas use grew at an annual rate of 6.3 percent. This growth was reversed in the mid-1970s as the market, saddled with a regulatory and contractual structure that did not allow price signals to be quickly or effectively transmitted throughout the system, began to decline. Curtailments of natural gas supplies to some high priority users, such as hospitals and schools, in the winter of 1976-77 highlighted the market imbalances and difficulties. Natural gas was increasingly viewed as a scarce and unreliable resource.

Congress reacted to the 1976–77 curtailments with legislation to encourage additional supplies of natural gas and to conserve natural gas for nonboiler fuel applications. This legislation, which included the Natural Gas Policy Act of 1978 (NGPA), initiated a major restructuring of the industry: a restructuring that is still evolving. The NGPA gradually removed price controls on much of the gas produced domestically, a process completed with the Natural Gas Wellhead Decontrol Act of 1989.

From 1972 to 1986, natural gas use dropped to less than three-quarters of the peak level. From the 1986 low of 16.2 Tcf, consumption has recovered, growing at an annual rate of 2.3 percent through 1998. This average rate of growth has occurred despite the leveling off of consumption in 1996 and 1997 at approximately 22 Tcf, followed by a 3-percent decline in 1998. This recent decline in consumption reflects the impact of moderate weather with lower heating demand during the past two heating seasons and the lower oil prices during the past year. The return of natural gas consumption to levels close to the peak of 25 years ago has been accompanied by dramatic market and regulatory restructuring. Some of these events include:

- Federal Energy Regulatory Commission (FERC) Orders 436 (1985) and 636 (1992) have altered the market for natural gas, splitting off or "unbundling" the commodity purchase from the transmission service.

- An entirely new contracting structure has developed for purchases of the commodity and also for services. Purchases of natural gas were once typically arranged under contracts of 20 or more years, but new "long-term" contracts may have terms of 1 or a few years.

- Gas production has shown a long-term increase, rising from 16.1 Tcf in 1986 to an estimated 19.0 Tcf in 1998, despite an average wellhead price of $2.03 per thousand cubic feet (in constant 1998 dollars) during the 1990s—49 percent below the 1983 peak of $3.99. Technological advances have enhanced the industry's ability to find and develop new gas reserves at competitive prices.

- Pipeline deliverability has increased sharply. At least 17 new interstate pipeline systems have been constructed since 1990, adding more than 8 billion cubic feet per day of capacity by the end of 1998. In addition, several pipeline expansions have been completed to bring greater flows from Canada. Today, the interstate pipeline system is a national grid with sufficient flexibility to move gas in many directions.

- New England, which for many years has been served principally by fuel oil, now has significantly greater access to natural gas. The expected flow of gas in late 1999 from the Sable Island project in the northern Atlantic off eastern Canada will further expand the potential for growth in the Northeast market.

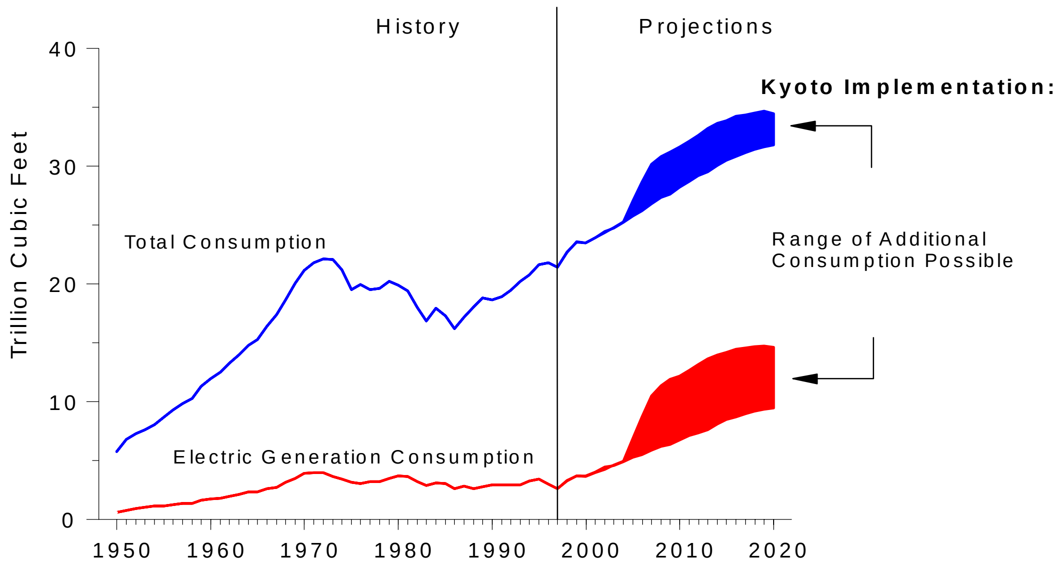
- Imports have taken a greater role in meeting supply. They supplied 4 to 5 percent of U.S. natural gas consumption in the early 1980s but provided about 14 percent in 1998.

- Price volatility has become a significant characteristic of the market, and financial markets have developed to facilitate the trade of natural gas and the hedging of prices.

Most notably, the perception of the availability of natural gas has changed from that of concern about scarce supplies to an assessment that the United States has relatively abundant resources. In the near term (1999–2000), growth in natural gas consumption will likely be related to the effect of more normal weather patterns and continued, although slowing, economic growth. Through 2020, the outlook for natural gas is robust with demand projected to

## Figure 1. Natural Gas Consumption Is Expected To Increase About 50 Percent by 2020 . . .

*. . . And even more if the Kyoto Protocol is implemented*




Note: The Energy Information Administration report *Impacts of the Kyoto Protocol on U.S. Energy Markets and Economic Activity* examines a series of six cases looking at alternative carbon emission levels. The reference case represents projections of energy markets and carbon emissions without any enforced reductions and is presented as a baseline for comparison of the energy market impacts in the reduction cases. The highest consumption patterns for natural gas are seen in some of the intermediate cases, principally the "Stabilization at 1990 Levels" and the "3 Percent Below 1990 Levels." For this figure, the reference case and the "3 Percent Below 1990 Levels" are used to illustrate a potential range of additional demand.

Source: Energy Information Administration, *Impacts of the Kyoto Protocol on U.S. Energy Markets and Economic Activity* (October 1998), AEO98 National Energy Modeling System runs KYBASE.D080398A and FD03BLW.D080398B.

grow to about 32 Tcf, an increase of about 50 percent from the 1998 level.[1] Further, as environmental concerns have led to proposals (such as the Kyoto Protocol) to limit carbon emissions worldwide, interest has heightened in the role that natural gas can play in meeting environmental goals. Natural gas is viewed as a relatively benign fossil fuel for the environment and is projected to play a large role in meeting targets associated with the reduction of greenhouse gases. If the Kyoto Protocol is implemented, gas usage could move as high as 35 Tcf by 2020.[2]

The concern about scarce natural gas supplies in the late 1970s led to limits on expansion of the gas market, particularly in the boiler fuel market. Since 1990, yearly consumption of natural gas for use in electricity generation has varied from 2.7 to 3.2 Tcf, down from 4 Tcf in the early 1970s. Now the future of natural gas is expected to be closely tied to electric generation, with consumption in that sector projected to climb to more than 9 Tcf in 2020—an annual rate of 4.5 percent from 1997. In 2020, electricity generation is expected to account for about 28 percent of natural gas consumption, slightly below the 32 percent consumed by the industrial sector. By contrast, in 1997, electricity generation accounted for about 15 percent of total natural gas consumption compared with 38 percent by industrial consumers of natural gas.

New generation capacity will be needed to meet growing electricity demand and to offset the expected retirement of nuclear plants. Major factors behind the increased use of natural gas in the electric generation sector are the lower capital costs, shorter construction lead times, and higher efficiencies associated with advanced combined-cycle plants in comparison with conventional pulverized coal plants. Part of the push for lower-cost generation and shorter construction lead times can be attributed to the impact of the restructuring of the electric generation and transmission industry. If the impacts of Kyoto implementation are taken into account, assuming no changes in domestic laws and policies, electric generation use of natural gas by 2020 could range from 12 to 15 Tcf. In some cases by 2010, electric generators could consume more natural gas than that consumed in any other sector.

*Natural Gas 1998: Issues and Trends* attempts to put industry developments within an environmental perspective, highlighting some of the issues associated with the impact of natural gas operations on the environment, as well as developments that will be necessary for natural gas to fulfill the role that has been projected. Some of the major topics addressed in the report are:

- **Near-term market effects of relatively mild winters the past 2 years.** The market for natural gas leveled off in 1997 and then declined by 3 percent in 1998 as mild winters have dampened seasonal gas demand**.** The lower-than-usual seasonal demand has contributed to lower prices, lower price variation, and flat domestic production levels. Storage operations are showing higher inventories than have been seen in several years. Additional pipeline and storage development has been slowing. A synopsis of these and other current data trends and developing issues is contained in Chapter 1 of the report.

- **Environmental effects of using natural gas.** Natural gas is a cleaner burning fuel than other fossil fuels**.** While natural gas does emit greenhouse gases, particularly carbon dioxide, the level of pollutants associated with its use is lower than for other fossil fuels. Chapter 2 summarizes and compares the emissions of natural gas relative to other fuels. It also provides a summary of other ways that the exploration, development, drilling, and use of natural gas affect the environment. And lastly, it illustrates some of the technology developments and other ways that natural gas can be used to reduce emissions.

- **Potential supply of natural gas.** With projections of a 50-percent expansion of the domestic natural gas market, questions arise about the sources of these additional supplies and technological developments that may be critical to meeting these projections. Some of the issues being addressed in the report include the expansion of the offshore production potential by the use of deep-water technology and the much longer-term potential of natural gas hydrates. As discussed in Chapter 3, gas hydrate resources are massive and dwarf current fossil fuel resources. The advent of gas hydrate production could have a major impact on energy supply patterns, energy consumption patterns, and prices of crude oil and products and conventional natural gas worldwide and in the United States. In the nearer term, the production of natural gas from deep water has increased significantly as technology has developed to facilitate and reduce costs associated with drilling in offshore water deeper than 1,000 feet (approximately 305 meters). This area has great potential and is seen as important to expanding domestic production levels. Chapter 4 analyzes recent production trends in the offshore Gulf of Mexico and examines the economics of offshore projects.

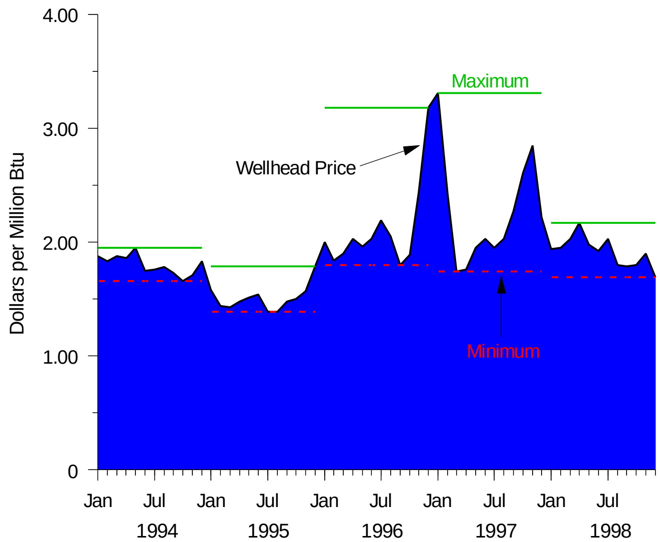
- Marketing and distribution of natural gas. In competitive energy markets, the pricing of natural gas and related services is critical to the marketability of natural gas, particularly to the expanding electric generation industry. With generation-dispatch decisions made continuously based on fuel costs, the cost and deliverability of natural gas to electric generation units is a critical component of the decision. The institutional and pipeline infrastructures associated with the delivery of natural gas are undergoing substantial adjustment and investment. Pipeline construction can require long lead times and large investments. Analysis of pipeline expansions requirements and accompanying investment requirements is presented in Chapter 5.

  Contractual arrangements for transporting natural gas that have been in place for 10 to 20 years are expiring and being renegotiated. These new contracts will provide more flexibility to shippers of natural gas, allowing them to adjust contractual terms to their needs, and potentially lower the cost of transmission services to many consumers. Chapter 6 presents analyses of developing trends in new contracts and capacity trading. In addition to the financial and contractual needs of the expanding market, new pipeline companies will be required to match supply sources with developing markets. Mergers of natural gas companies in all aspects of the industry from production through distribution with other natural gas companies or with other energy entities portend a new era in the provision of natural gas services. Chapter 7 presents an analysis of what is behind these mergers and how service to consumers is likely to be affected.

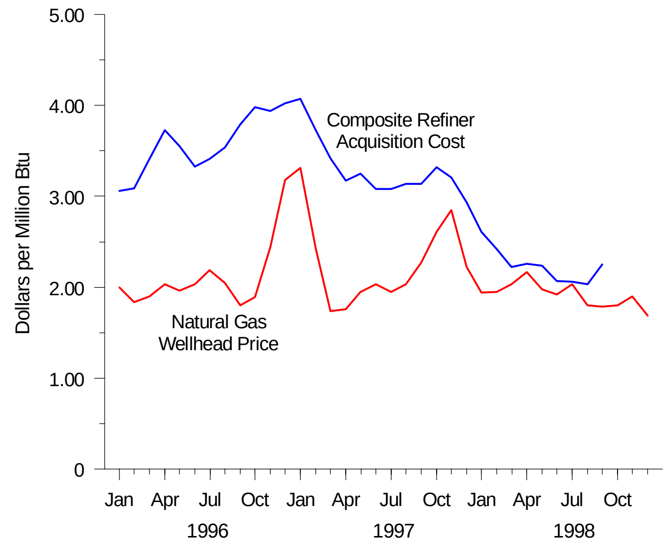
The opportunities available to the industry are substantial. The natural gas market is projected to show significant growth over the next 20 years because North American natural gas resources are considered both plentiful and secure and their increased use relative to other fossil fuels can reduce levels of harmful emissions.

## Figure 2. Price Variation Is a Significant Characteristic of the Market

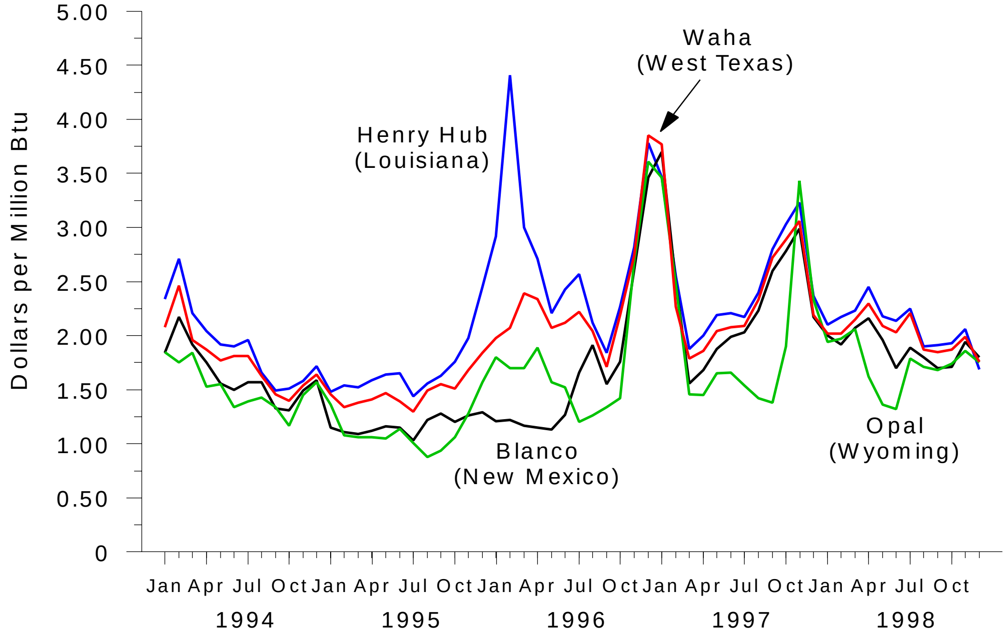
***The range between the lowest and highest prices for the year moderated during 1998***




***The recent decline in petroleum prices has put downward pressure on natural gas prices***




***Natural gas spot prices at four regional hubs show improved, yet incomplete, integration of markets***




Sources: Energy Information Administration (EIA), Office of Oil and Gas. **Wellhead Prices:** derived from EIA: 1980-1982—*Historical Monthly Energy Review 1993*, October 1998—*Natural Gas Monthly* (December 1998), November and December 1998—*Short-term Energy Outlook 4th Quarter* (1998). **Refiner Acquisition Cost:** *Monthly Energy Review* (December 1998). **Spot Market Prices:** Financial Times Energy, Inc., *Gas Daily*.

# Wellhead and Spot Market Prices

Prices are an important indicator of the industry's capability relative to current market requirements. Prices also are a bellwether of future trends, and so the decline in natural gas prices from 1997 to 1998 is interesting both as a measure of current industry performance and for the implications for likely developments in the next few years. The average wellhead price in 1998 was $1.92 per million Btu (MMBtu), which is $0.34 or 15 percent less than in 1997.[3] Prices declined from 1997 to 1998 at least in part because of mild weather that lowered demand. Additional downward pressure on prices was provided by abundant gas supplies from both domestic and foreign sources, as well as interfuel competition driven by lower oil prices.

- **After significant increases in the previous 2 years, the average wellhead price declined in 1998 as warmer-than-normal weather and abundant stock levels dominated the marketplace.** The 15-percent warmer-than-normal temperatures in 1998 helped reduce consumption by an estimated 683 billion cubic feet (Bcf) or 3 percent from the previous year. Domestic production increased only slightly, by 75 Bcf, which was somewhat surprising in light of continually weakening prices in the latter half of the year. Foreign supplies also increased, with estimated net imports rising 134 Bcf as crossborder capacity expansion increased. These factors combined to produce a generally downward price trend from the monthly peak of $2.85 per MMBtu in November 1997 to the low of $1.69 in December 1998.[4] Along with the decline in the wellhead price, the range of monthly prices in 1998 was only $0.48 per MMBtu, compared with $1.37 in 1996 and $1.57 in 1997 (Figure 2).

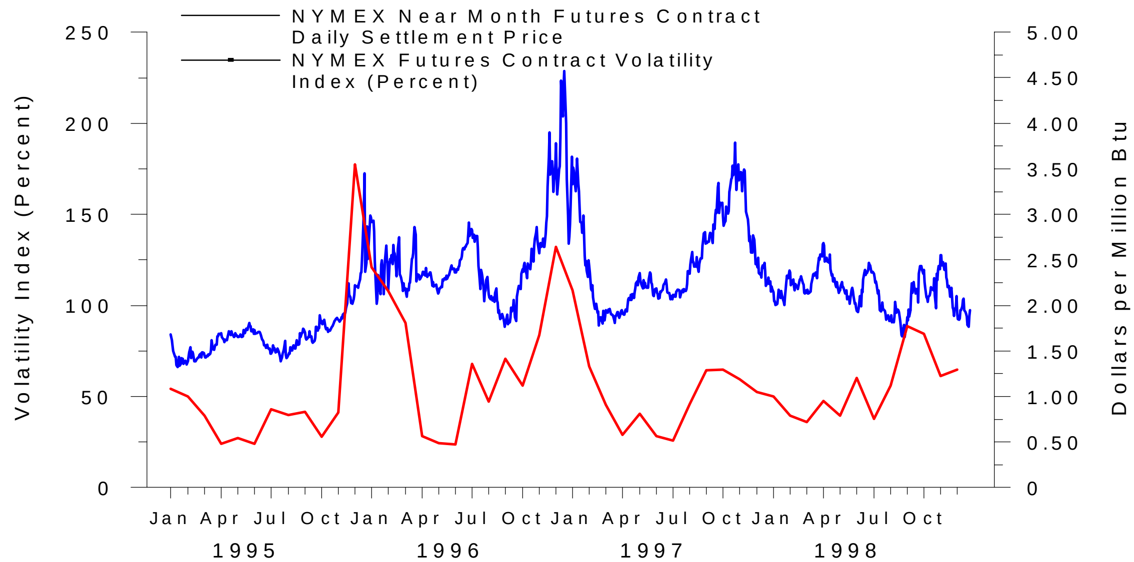
- **A counterseasonal pattern similar to that in 1997-98 is evident in the 1998-99 winter as monthly prices declined after an increase early in the season.** During the past few years, storage-related concerns have led to price increases before or at the start of the heating season. As the 1997-98 heating season approached, prices were driven upward by expectations related to storage levels. Working gas in storage at the end of October 1997 was 2.89 trillion cubic feet (Tcf), only slightly above the initial 2.80 Tcf for the previous heating season, during which average prices peaked at $3.31 per MMBtu in January. This price increase was driven at least partially by the reluctance of storage operators to draw down stock levels heavily in the initial portion of the heating season. However, temperatures were unusually warm in late 1997, unlike in the prior year, reducing demand. The lack of market fundamentals supporting higher prices caused prices to fall from November 1997 to January 1998. Prices then began to climb to a peak of $2.16 in April. After the heating season, firms began to refill storage at accelerated rates in response to forecasts calling for unusually hot summer weather in many parts of the United States. The forecasts, however, proved accurate only for the Southwest, and so prices subsequently declined. The low prices did contribute to high storage refill rates, resulting in the highest stock levels in 4 years at the start of the 1998-99 heating season. High storage levels and warm weather were primary factors contributing to a sharp decline ($0.21) in the average wellhead price from $1.90 per MMBtu in November to $1.69 in December 1998.

- **Competitive pressure from a steady decline in petroleum prices during 1998 has contributed to the relative "softness" of gas prices**. The composite refiner acquisition cost of a barrel of crude oil averaged 33 percent less in the first three quarters of 1998 compared with the corresponding period of 1997. As prices for the raw product fell, refined petroleum product prices declined but to a lesser degree. The 15-percent decline in yearly natural gas prices between 1997 and 1998 is consistent with the expected downward pressure from petroleum competition. Monthly gas and oil prices were unusually close to parity for much of 1998 (Figure 2).

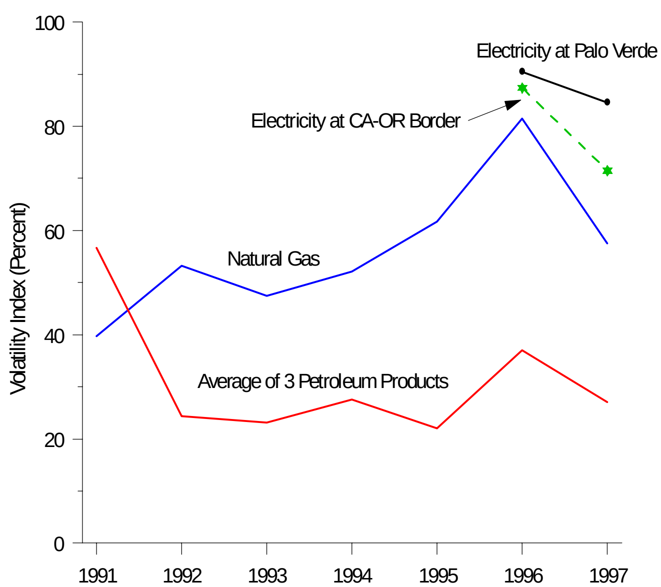
- **Monthly spot prices show increased convergence as the network expands to improve interconnections between regional markets.** Market hub prices in the initial years of open-access transportation were rather strongly correlated.[5] As markets evolved, however, the physical network did not reflect the growing needs of the system. By 1996, obvious examples of price divergence between regions appeared. In February, prices spiked at the Henry Hub as a sudden cold snap caused demand to soar in northern markets, but other markets were relatively unaffected. Prices at Blanco and Opal in 1995 and most of 1996 were persistently below and not conforming to the patterns seen elsewhere. Major capacity expansions in mid-1996 helped to alleviate transmission bottlenecks at the San Juan Basin (near Blanco) and allowed more New Mexico gas to get to Midwest and Eastern markets. Additionally, daily pipeline capacity for moving gas from the central Rocky Mountain area (Opal, WY) to the Southwest has grown by more than 60 percent since 1990. These actions have helped to improve interconnections between regional markets, however, continuing price disparities indicate that further adjustments are necessary to achieve an integrated North American network (Figure 2).

# Figure 3. Futures Trading Is a Key Component of Efficiently Functioning Natural Gas Markets

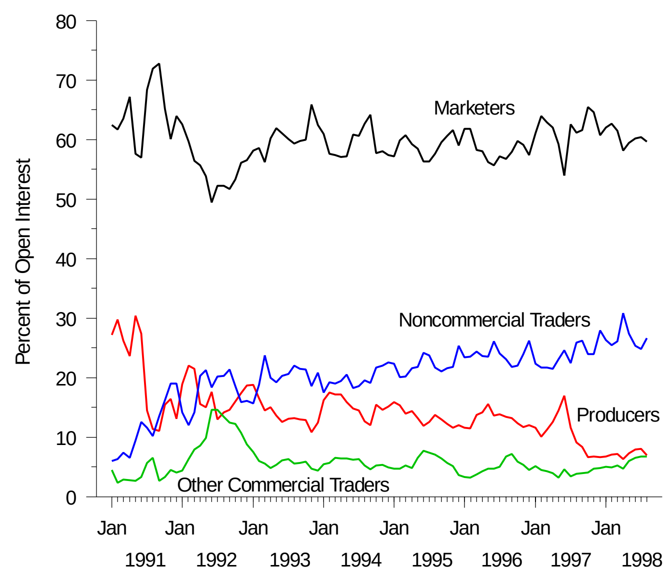
***The volatility of natural gas futures prices at the Henry Hub declined over the past 2 years***




***Natural gas is second only to electricity in energy futures price volatility***




***Marketers and noncommercial traders dominate trading in natural gas futures contracts***




NYMEX = New York Mercantile Exchange.

Note: The price volatility illustrated in these graphs is the annualized standard deviation of daily price changes expressed in percentage terms. This volatility measure is "annualized" by multiplying the standard deviation corresponding to the series of daily prices being examined (here, monthly and annually) by the square root of 250, the approximate number of trading days in a year. For lower right graph, see endnote 7 for descriptions of trader categories.

Sources: **NYMEX Near-Month Futures Contract Settlement Prices:** Commodity Futures Trading Commission. **Volatility Indices:** Energy Information Administration (EIA), Office of Oil and Gas. **Reportable Interest in Natural Gas Futures Contracts:** New York Mercantile Exchange.

# Natural Gas Futures Market

The range of settlement prices of the New York Mercantile Exchange (NYMEX) near-month futures contract for delivery at the Henry Hub[6] narrowed markedly in 1998 with respect to the previous 3 years. The spread between the highest and lowest prices in 1998 was just over $1.00 per million Btu (MMBtu), while in each of the previous 3 years this spread exceeded $2.00, reaching an all-time high of $2.81 in 1996. In fact, only 1991 had a narrower spread than 1998, but only by $0.035. Contrary to the normally expected pattern of prices peaking in the third or fourth quarter, 1998 futures prices reached their highest level in the spring; from there the trend was down. Despite rallies in the summer and at the beginning of the heating season, the futures price dropped nearly one-third from its April high of $2.689 per MMBtu, ending the year at $1.945.

- **During the past 2 years, the price volatility of the NYMEX futures contract has declined** (Figure 3). Not surprisingly, the price volatility of the near-month futures contract tends to be greater during heating season months and less in the summer months, reflecting the increased levels of and swings in demand together with greater uncertainty about the availability of supply. In the three heating seasons prior to 1998-99, colder-than-normal November weather and concerns about the adequacy of storage levels contributed to futures prices spiking to peaks in the fourth quarter. Despite these peaks, price volatility has been declining since the 1995-96 heating season. This decline is partly attributable to the fact that the December-through-March periods of both 1996-97 and 1997-98 had somewhat milder weather than average. By contrast, 1998 futures prices peaked at the beginning of the second quarter. From this point to the end of the year, the general trend was down, as market fundamentals of large and uninterrupted supplies, moderate demand, and a robust stock build prevailed. The beginning of the 1998-99 heating season saw a run of warmer-than-normal weather in November and early December, and, with storage inventories on November 1 at a 6-year high, futures prices collapsed in the final 2 months of 1998.

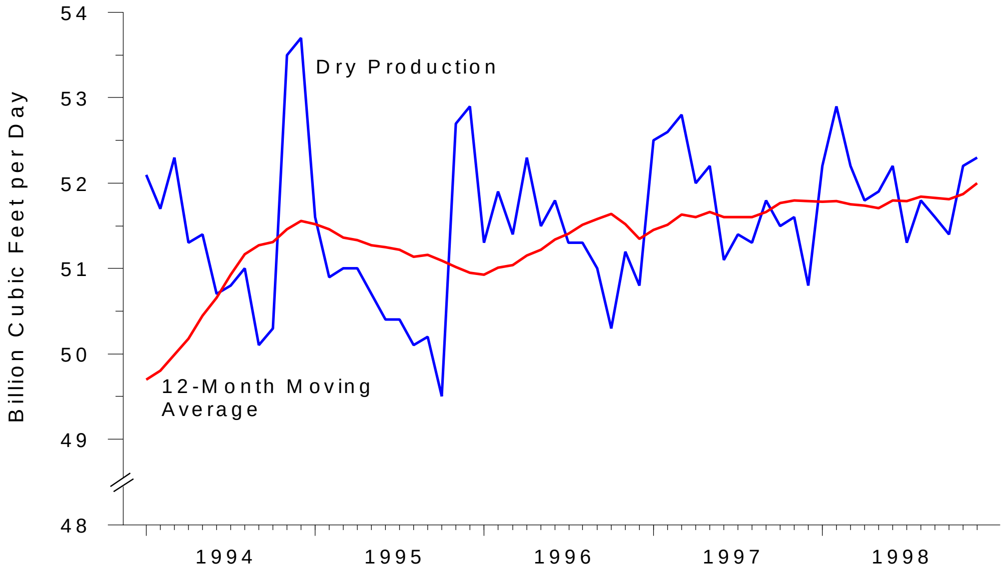
- **Despite the decreased volatility during 1998, natural gas futures price volatility is the second highest of all energy sources.** Price volatility in the natural gas market generally exceeds volatility in markets for other energy as well as other commodity markets (Figure 3). A number of characteristics of the gas market contribute to this volatility. For instance, the variability of end-use consumption of natural gas directly affects gas flow in the transmission and distribution network, requiring constant adjustment of market supplies to maintain system integrity under changing delivery conditions. Further, pipeline capacity can be constrained under certain conditions. Also, about 86 percent of annual gas consumption is supplied by domestic production, yet production offers limited flexibility in flow rates. During the heating season, storage is the primary source of swing supply, satisfying as much as 80 percent of demand in some areas on peak days. Thus, markets are particularly sensitive to stock levels leading up to, as well as during, heating seasons. Yet storage levels can be quite variable, since stocks at any point during the heating season reflect the outcome of myriad decisions to withdraw or replenish stored gas, which affect, and are affected by, any number of economic factors regarding supply and price and the market's perception of these factors.

- **Since the launch of the Kansas City Board of Trade (KCBOT) futures contract in 1995, its trading volume has leveled off at less than half the level of its first month of trading, while the NYMEX Henry Hub trading volume has continued to grow.** The monthly number of KCBOT contracts traded has yet to return to the level recorded in that contract's first month, when over 19,000 contracts were traded. Since February 1996, monthly trading volumes have fallen in a range of about 4,000 to 10,000. By contrast, trading of the NYMEX Henry Hub contracts has continued to grow. The yearly total of NYMEX contracts traded increased by 9 percent from 1995 to 1996, by 35 percent the following year, and by 34 percent in 1998. There continues to be an order of magnitude difference in trading between the two contracts, as monthly trading volumes of the NYMEX contracts have exceeded 1 million since August 1997.

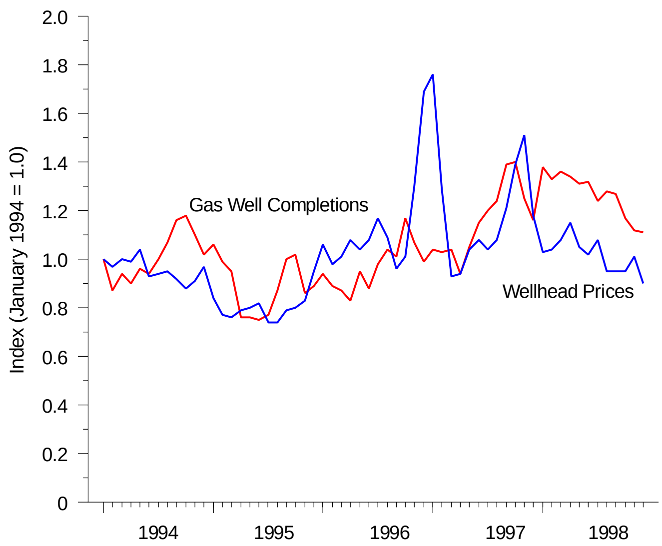
- **Natural gas marketers control the largest proportion of open interest in NYMEX Henry Hub futures contracts.** They typically hold around 60 percent of total monthly reportable open interest (Figure 3).[7] The share of open interest held by noncommercial traders, such as financial firms and mutual and hedge funds, has steadily increased since the beginning of natural gas futures trading. Today, they hold about 25 percent of monthly reportable open interest. Producers' proportion of open interest has tended to decline over the years and since October 1997 has remained at about 7 percent. The share held by all other commercial traders has held fairly constant over the past 5 years at just over 5 percent. Based on current NYMEX Henry Hub trading levels alone, on any given trading day, marketers control the disposition of about 2.2 to 2.6 trillion cubic feet of gas, speculators about 1 trillion cubic feet, and producers and other hedgers about 200 to 300 billion cubic feet.

## Figure 4. Annual Natural Gas Production Is at its Highest Level Since 1981, 19.0 Trillion Cubic Feet in 1998

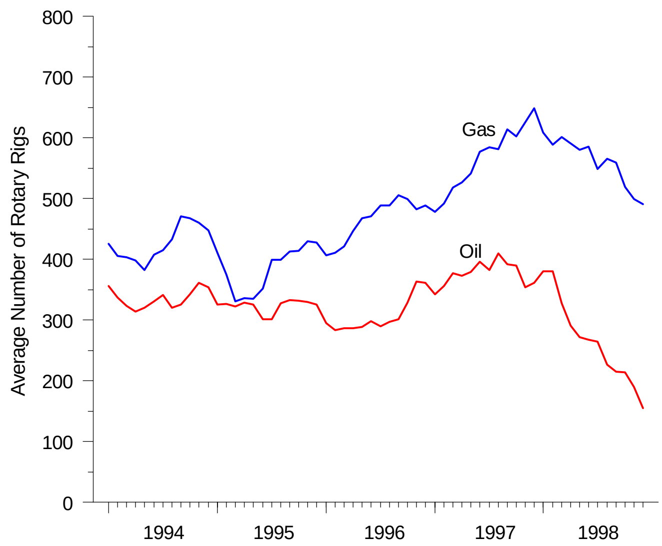
***Dry natural gas production has been slowly increasing . . .***




***. . . But the growth in gas well completions slowed in 1998***




***Still, the gap between gas and oil drilling rigs continued to increase in 1998***




Sources: Energy Information Administration (EIA), Office of Oil and Gas. **Production and Wellhead Prices:** derived from EIA, *Natural Gas Monthly*, various issues. **Gas Well Completions:** EIA's Well Completion Estimation Procedure (WELCOM) as of April 5, 1999. **Rotary Rigs:** EIA, *Monthly Energy Review*, various issues.

# Natural Gas Production

Dry natural gas production has been increasing slowly during the past several years. Production in 1998 is estimated to be 19.0 trillion cubic feet, 75 billion cubic feet (Bcf) more than in 1997. The 1998 level is the highest since 1981 when 19.2 trillion cubic feet was produced.[8] As production has grown in recent years, the differences in daily production rates in each month have narrowed (Figure 4). During 1994, production in any month was between 50.1 to 53.7 Bcf per day, a difference of 3.6 Bcf per day. For 1998, the estimated low and high rates are 51.3 and 52.9 Bcf per day, respectively, for a difference of only 1.6 Bcf per day. More stable production rates during the year may be attributable to increased availability and use of storage by producers, and slightly lower monthly peak consumption levels because of less severe temperatures during recent winters.

- **Conventional nonassociated production in the onshore Lower 48 States was 7.4 trillion cubic feet (Tcf) in 1997, accounting for the largest share of U.S. production, 39 percent.**[9] The 1997 level was virtually unchanged from that of 1996. Conventional nonassociated production has been in the range of 7 to 9 Tcf since the mid-1980s after experiencing a strong downturn the previous 10 years. Production from this source had peaked at nearly 14 Tcf in 1973. In recent years, the natural decline in production from mature fields has been countered, in part, by technological improvements. Horizontal drilling and 3-D seismic studies have slowed the rate of production declines and found new natural gas resources.

- **Dry natural gas production from the offshore Lower 48 States increased about 91 Bcf (2 percent) in 1997, reaching 5.6 Tcf.** Because of drilling restrictions in the Atlantic and the Pacific, almost all domestic offshore production comes from the Gulf of Mexico. Deep water areas of the Gulf are a prime growth area for domestic gas production. In June 1997, Shell Deepwater set a new water-depth record for production as gas began to flow from Shell's Mensa field located in 5,376 feet of water.[10]

- **Natural gas production from unconventional sources in the onshore Lower 48 States grew by 32 Bcf (1 percent), reaching 3.7 Tcf in 1997.** Unconventional production includes natural gas from coalbeds, Devonian shale, and tight sands. It has been the largest contributor to increased gas production during the 1990s, growing at an average annual rate of 4.3 percent from 1990 through 1997. The outlook for continued production growth is uncertain, however, because the qualifying period for new wells to receive a special production tax credit ended in the early 1990s.[11]

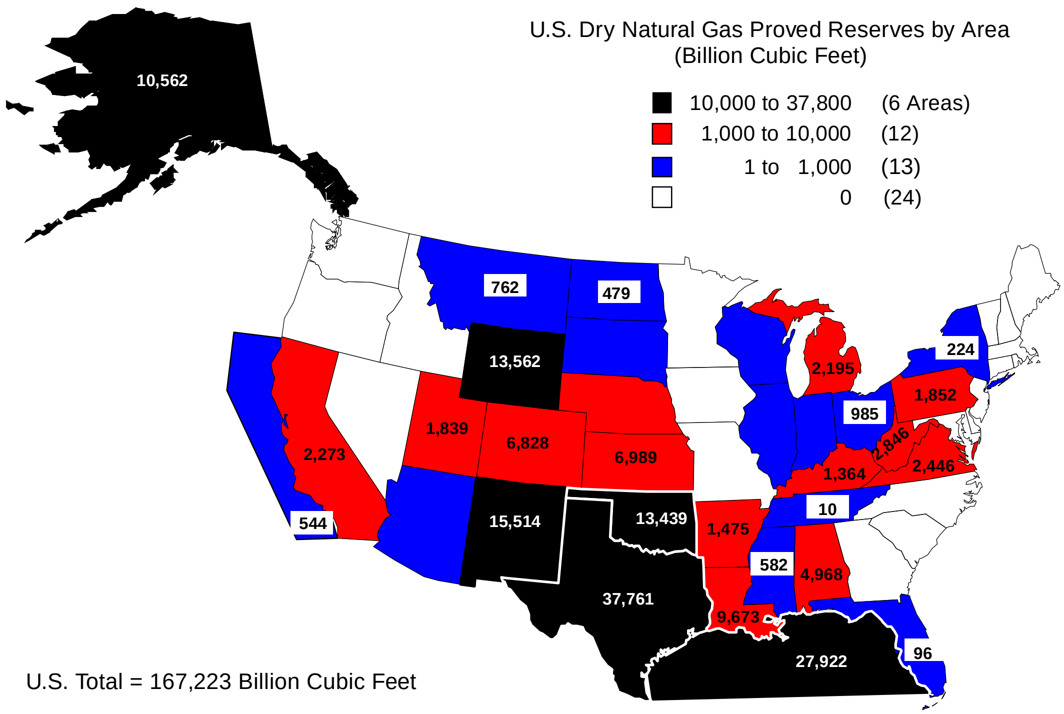
- **Monthly natural gas well completions gradually declined during 1998 in response to generally lower wellhead prices** (Figure 4). Monthly completions[12] have risen since mid-1995 as wellhead gas prices increased, although that trend reversed itself as market conditions worsened in 1998. Gas well completions in 1997 were 19.6 percent higher than in 1996. The 10,937 wells reflect the growth in average wellhead price, which rose to $2.32 per thousand cubic feet (Mcf) in 1997—its highest yearly level during the 1990s. Despite a slight price peak of $2.22 per Mcf in April 1998, the highest level for all months in 1998, prices generally have been below the average of the previous 2 years. Drilling began at a relatively high level in the early months of 1998. However, it declined thereafter as wellhead prices declined to $1.73 per Mcf in December and to $1.96 per Mcf for the year. Although gas wells in 1998 grew to 11,907, the low gas prices projected for 1999 are likely to result in reduced gas drilling at least in the short term.

- **The Gulf Coast region saw the largest number of natural gas wells drilled in 1998, while the Rocky Mountain region had the largest increase compared with 1997.**[13] Gas well drilling in the Gulf Coast region (including offshore) has generally increased since 1992.[14] The 19-percent increase in 1998 brought the number of new gas wells in this region to 2,837. Gas well completions in the Rockies reached 2,733 wells in 1998, an increase of 881 wells or 48 percent. This was the second year of drilling increases for the area after 3 years of decline. Overall, gas well completions in the Lower 48 States increased by 9 percent in 1998, reaching an estimated 11,902 wells. Drilling in the Northeast has generally declined throughout the 1990s. The Northeast is the only region where drilling declined in 1998, falling by 394 wells or 15 percent.

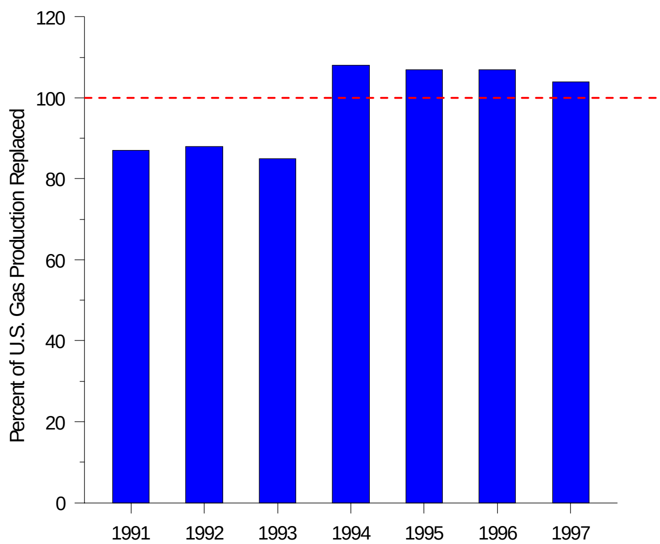
- **The gap between the number of drilling rigs directed toward natural gas and crude oil generally increased during 1998** (Figure 4). Natural gas rotary rigs have exceeded oil rigs for several years, but the gap has grown since early 1997.[15] Relatively weaker crude oil prices have led the push toward natural gas drilling domestically. Rig counts for 1998 show that the average number of rotary rigs for both oil and gas has fallen, but while gas rigs exceeded oil rigs by only 60 percent in January 1998, they were triple the oil rigs running in December 1998—491 gas rigs compared with 155 oil rigs.

## Figure 5. U.S. Proved Reserves Totaled 167.2 Trillion Cubic Feet at Year-End 1997

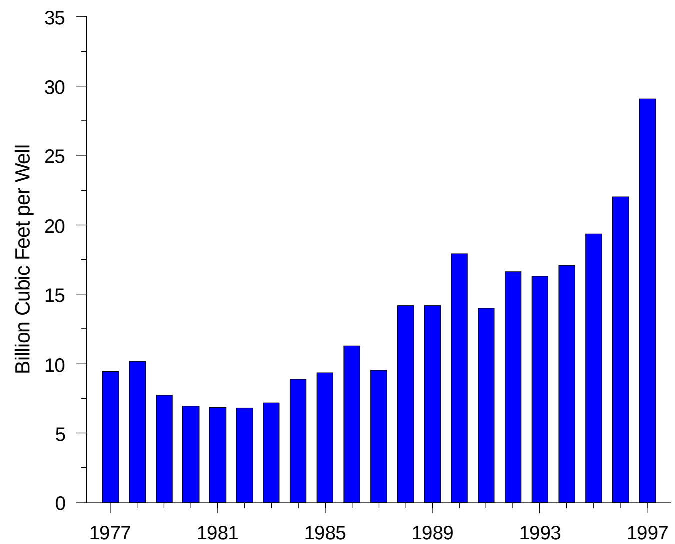
*Six areas contain 71 percent of U.S. dry natural gas proved reserves*




*Reserve additions exceeded U.S. natural gas production 4 years in a row*




*Gas discoveries per exploratory gas well have been trending up since the mid-1980s*




Source: Energy Information Administration, *U.S. Crude Oil, Natural Gas, and Natural Gas Liquids Reserves: 1997 Annual Report* (December 1998).

# Reserves and Resources

U.S. proved reserves of natural gas moved 0.4 percent higher in 1997 to 167.2 trillion cubic feet (Tcf). Proved reserves are in effect the on-the-shelf inventory of natural gas from which production is obtained, and thus are an important indicator of near-future gas production potential.[16] This was the fourth consecutive increase in natural gas reserves, following a downward trend evident since the early 1980s. Via the exploration and development process, proved reserves are replenished from the natural gas resources that exist as unproven volumes either in known fields or in fields yet to be discovered. Estimates of unproven natural gas resources are less certain than those of proved reserves and are the object of considerable study owing to the important role they play in formulating the future energy outlook.

- **Proved reserves of dry natural gas showed yearly increases of 1.3 to 1.4 Tcf from 1994 through 1996, with a smaller (0.8 Tcf) increase in 1997.** The smaller 1997 increase was primarily caused by a combination of negative adjustments and higher production. The 4-year increase in reserves of almost 3 percent brought the level to 167.2 Tcf at year-end 1997. The majority of proved gas reserves are located in the onshore and offshore Gulf Coast area. Texas, Louisiana, Mississippi, Alabama, and the Gulf of Mexico Federal Outer Continental Shelf (OCS) had 80.9 Tcf, which is 51.6 percent of the total for the Lower 48 States.

- **Proved reserves increased despite an almost 8 percent increase in production during the 4-year period.** Reserve additions replaced nearly 106.5 percent of production (1994 through 1997), arresting the prior long-term decline in proved reserves. Total discoveries[17] in the period were 51.2 Tcf, and the net sum of revisions and adjustments was 27.9 Tcf. Reserve additions associated with the phenomenon of ultimate recovery appreciation (i.e., field growth)[18] were 71.5 Tcf, representing 90.2 percent of total reserve additions. New field discoveries of 7.7 Tcf made up the rest.

- **The average volume of discoveries per exploratory well increased by 32 percent from 1996 to 1997.** The net 4-year increase of proved gas reserves in the Lower 48 States was nearly 4 Tcf, and in Alaska 0.8 Tcf. The element underlying this performance has been a substantial increase in discoveries per exploratory gas well completion (Figure 5). Exploratory wells include new field tests (wildcats), which discover new fields, new reservoir tests, which discover new reservoirs in previously discovered fields, and extension tests, which expand the proved areas of previously discovered reservoirs.

- **Recovery from coalbed methane deposits, located principally in New Mexico, Colorado, Alabama, and Virginia, has grown rapidly in recent years.** Coalbed methane reserves accounted for nearly 7 percent of 1997 proved gas reserves, and coalbed gas constituted over 5 percent of 1997 gas production. Most of the increase of coalbed methane proved reserves and production occurred before 1995, subsequent to which they have increased only about 9.2 and 14 percent, respectively.

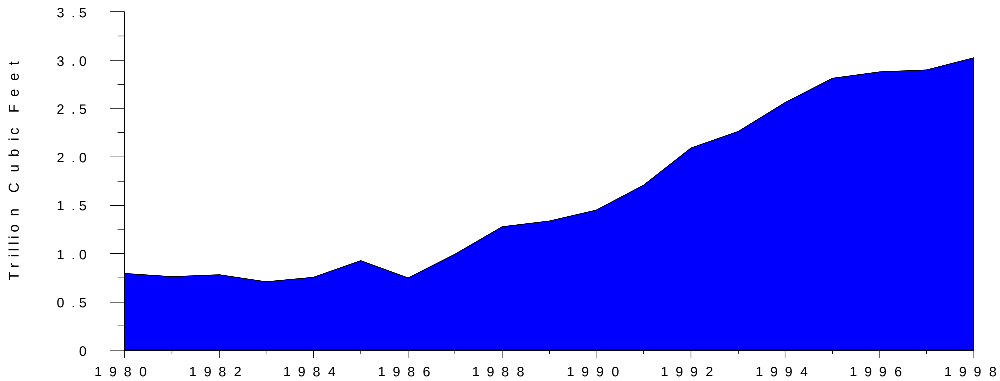
- **The Nation has a technically recoverable natural gas resource base of 1,156 Tcf remaining to be tapped (exclusive of proved reserves and Alaskan gas).**[19] Estimates of the Nation's oil and gas resources are periodically developed by the U.S. Geological Survey (USGS) for onshore lands and those under State-jurisdiction waters, and by the Minerals Management Service (MMS) for those lands under Federal OCS waters. These estimates are substantially better founded than those produced just a few years ago. For natural gas, they are confirmed at the national level by estimates developed independently by the industry-based Potential Gas Committee using different methods and data sources.

- **The mean estimates of undiscovered technically recoverable *conventional* natural gas resources in the onshore Lower 48 States and State waters are 155.9 Tcf for nonassociated gas and 34.5 Tcf for associated-dissolved gas.**[20] However, not all technically recoverable resources are likely to be economically recoverable. For example, the USGS has estimated that only 79 Tcf of the nonassociated gas accumulations in the onshore Lower 48 States has unit costs (inclusive of discovery, development, and production) no greater than $2.45 per thousand cubic feet.[21] A large proportion of remaining undiscovered resources are expected to be in small fields, which have inherently higher unit costs.

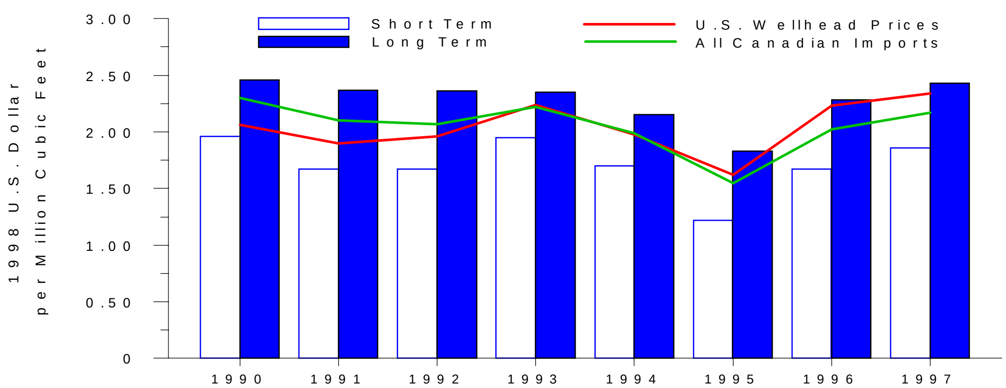
- **Approximately one-half of the remaining untapped natural gas resource base underlies federally owned lands,[22] which has important implications for future supply.** These resources are split about evenly between onshore and offshore locations. However, in recent years environmentally motivated concerns have led to the imposition of leasing and/or drilling moratoria in many Federal onshore and offshore areas. Oil and gas drilling is presently prohibited along the entire U.S. East Coast, the west coast of Florida, and all of the U.S. West Coast except a few areas off the coast of southern California. Drilling in Alaska is allowed off the Arctic Coast in the Gulf of Alaska and in Cook Inlet/Shelikoff Strait.

## Figure 6. U.S. Gas Trade with Canada Reflects Growing Competition

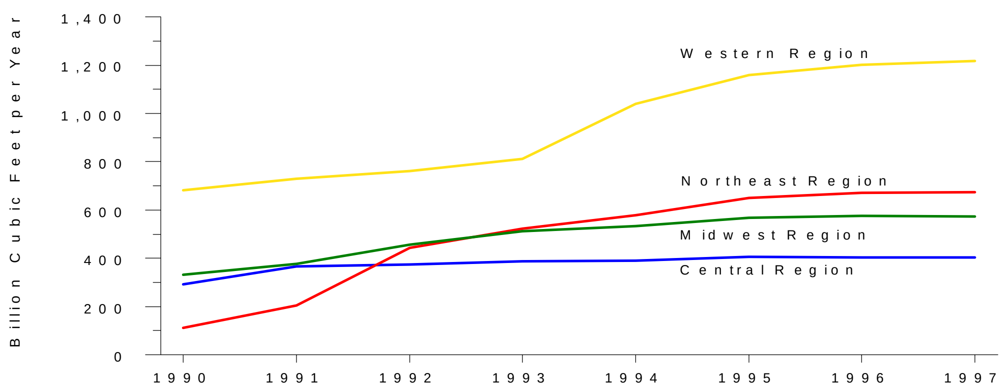
***After growing almost 16 percent yearly from 1986 to 1995, imports from Canada have grown only 1.5 percent since 1995***




***Competitive prices are a key factor in growing Canadian sales to the United States***




***Growth in imports from Canada in recent years has been led mainly by greater imports to the Western Region***




Note: The regions shown in the bottom figure are identified in the map on page 18.

Sources: Energy Information Administration (EIA). **Imports of Canadian Gas:** EIA, *Natural Gas Monthly* (February 1999) and *Monthly Energy Review* (December 1998). **U.S. Wellhead Price and Average for All Canadian Imports:** EIA, *Natural Gas Monthly* (August 1998) and *Natural Gas Annual 1997.* **Average Prices Under Short-term and Long-term Authorizations:** EIA, derived from Office of Fossil Energy, *Natural Gas Imports and Exports*, various issues.

# Foreign Trade—Canada

Canada remains by far the largest foreign supplier of natural gas to the United States, achieving a record volume of 3.0 trillion cubic feet (Tcf) in 1998. This represented 96.7 percent of all natural gas imports to the United States and 14 percent of total U.S. consumption. This record volume was achieved although annual growth has slowed substantially since 1995 (Figure 6). Gas imports are bounded by the available crossborder capacity, which increased again in 1998 with the opening of new facilities, such as the major expansion project along the Northern Border system. This project increased import capacity by 0.7 billion cubic feet (Bcf) per day at a cost of roughly $800 million. Virtually all Canadian gas (99 percent in 1997) is produced from the Western Canadian Sedimentary Basin (WCSB), which is located primarily in Alberta but extends into British Columbia, Saskatchewan, and Manitoba. The expected late-1999 opening of the Sable Island project in the northern Atlantic is seen as a change with potentially far-reaching consequences as it will be the first commercial production of natural gas from a major Atlantic field off North America.

- **The price of natural gas imports from Canada has declined relative to U.S. wellhead prices during the 1990s.** The average border price for gas imports from Canada exceeded U.S. gas wellhead prices by 10 percent in 1990. However, by 1997, the average import price of $2.15 per thousand cubic feet (Mcf) was 7 percent below the U.S. wellhead price. The increasing competitiveness of Canadian supplies may be attributed to two related factors. First, operators of the capacity expansions during the period, especially in the West, have relied on price-responsive short-term authorizations to market the incremental flows from Canada. The share of imports purchased under short-term authorizations rose from 28 to 52 percent during this period. Secondly, although long-term authorizations tend to exhibit relatively stable average prices, more price flexibility even in these arrangements seems apparent in recent years (Figure 6).

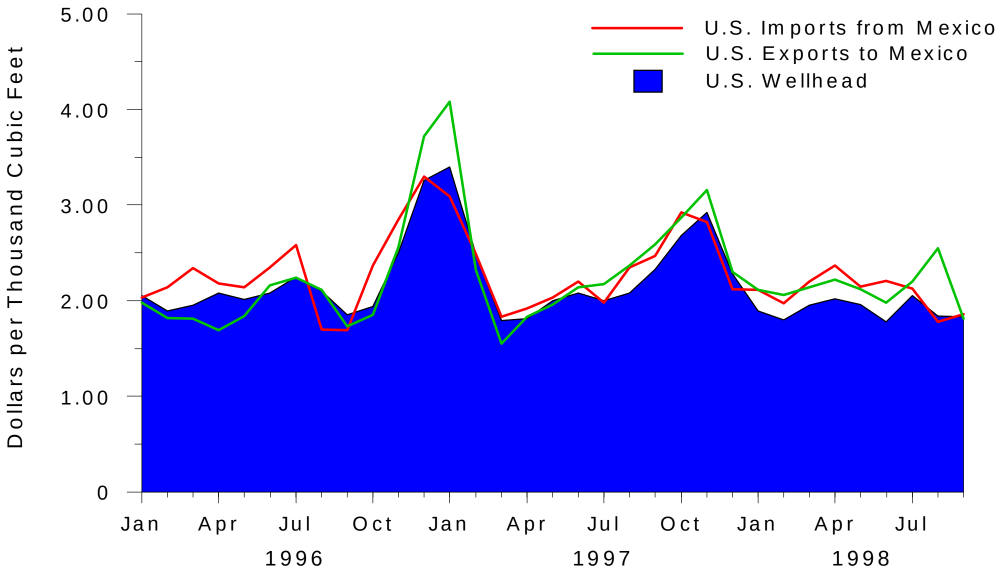
- **Capacity limitations in recent years have slowed the growth of U.S. imports from Canada.** Canadian gas volumes volumes imported into the United States during 1997, only 2.9 percent more than the 1995 level, likely would have been considerably greater had more mainline transmission capacity been available to shippers. U.S. imports of Canadian gas grew by 4.5 percent to 3.0 Tcf in 1998 as additional capacity became available. Almost all large-capacity crossborder pipelines from Canada have shown high utilization rates in recent years. Given a typical seasonal utilization pattern, it is very likely that these lines were utilized at or in excess of their certified capacity levels during peak demand periods. In fact, according to 1996 usage patterns, import lines with capacity of more than 250 million cubic feet (MMcf) per day, with the exception of the Empire Pipeline (a "Hinshaw" pipeline),[23] had an overall average utilization rate of 92 percent. The rate for those large-capacity lines dwarfs the 59-percent utilization of the smaller lines. The low utilization rates for smaller lines often reflect their intended use for peak-season requirements, dedicated use for a single customer, or support of storage operations, rather than a lack of demand itself. Another sign of significant pent-up demand for additional imports from Canada is the great interest in proposed expansions during the open-season exercises held by pipeline companies testing potential markets.

- **The largest import volumes from Canada flow toward West Coast markets, principally in California**. Imports directed to West Coast markets are transacted mainly under short-term authorizations, 76 percent in 1997, which significantly exceeds the next highest regional fraction of 46 percent for the Central Region. This reliance on short-term arrangements contributed to continued or expanded flows by allowing prices to respond competitively as conditions changed (Figure 6). Import volumes to all regions have increased during the 1990s, with the largest growth by far, both absolutely and proportionally, in the Northeast, where annual gas receipts from Canada increased more than 550 Bcf from 1990 to 1997. Expanded flows to the Northeast were facilitated by construction and expansion of crossborder transmission capacity.

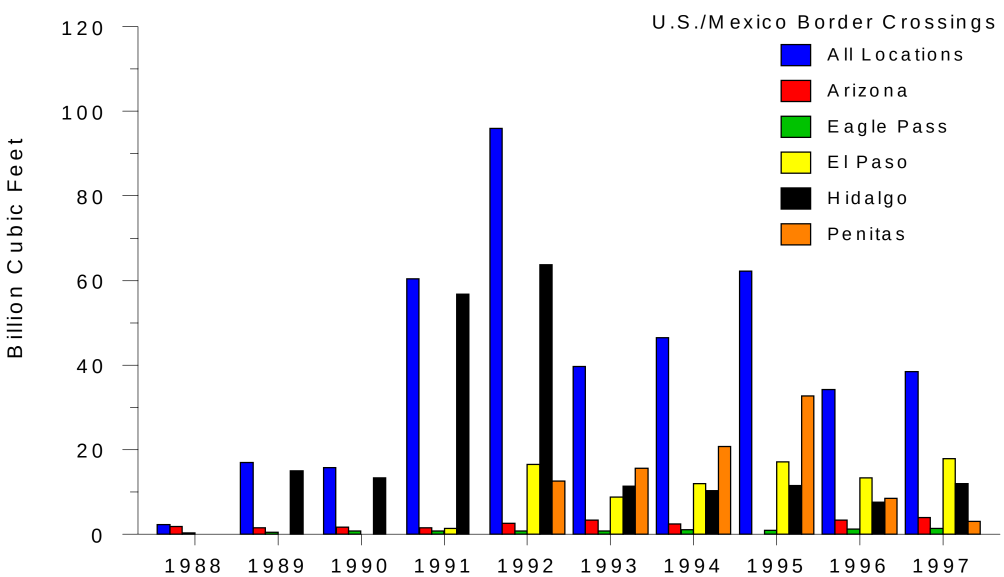
- **Planned expansions would add approximately 3.7 Bcf per day to crossborder pipeline capacity during 1999 and 2000.** The largest project is the Alliance pipeline, which was designed to bypass the capacity-constrained existing system. Alliance was originated by a group of western Canadian producers, although most of their interests have been bought out since by pipeline companies and other shipping concerns. Producers thought that the market potential was present for greatly expanded sales of gas from the WCSB. The economics of the Alliance pipeline is enhanced by its fairly unique ability to ship "wet" natural gas, which is natural gas that has not been processed to remove hydrocarbon liquids. The liquids will be removed at the terminus of the line, just south of Chicago, Illinois. The natural gas liquids then will be sold at the generally higher U.S. prices, thus enhancing the total return to producers.

## Figure 7. U.S. Gas Trade with Mexico Is Expected To Grow as the Industry Expands on Both Sides of the Border

***Price movements show the increasing interrelatedness of North American gas markets***




***U.S. gas exports to Mexico from El Paso, Texas, were roughly 40 percent of all exports during 1996 and 1997***




Note: Border crossing data in lower figure exclude volumes exported at Calexico, CA, and Clint, TX, both of which began flows in 1997 and comprised only 1 percent of the total volume

Source: Energy Information Administration, Office of Oil and Gas, derived from data collected quarterly by Department of Energy, Office of Fossil Energy.

# Foreign Trade—Mexico

Mexico has been a net importer of small volumes of U.S. natural gas in the 1990s, with considerable variation in yearly net flows. Mexico has faced significant economic difficulties that have affected its yearly gas imports. Although U.S. gas exports are estimated to have reached 50 billion cubic feet (Bcf) in 1998, they remain only 52 percent of the 1992 peak. However, Mexican consumption of natural gas could grow at unprecedented rates, driven by demand growth and regulatory reform that is opening up parts of the industry to foreign investment. Additional demand growth also is expected as the Mexican tariff on imported U.S. gas declines. The North American Free Trade Agreement (NAFTA) established a 10-percent tariff, commencing in 1993, that is reduced 1 percent annually. Removal of the tariff, which was 5 percent in 1998, was the subject of unsuccessful negotiations in 1998.

- **Prices paid for gas traded between the United States and Mexico have differed on average by less than 7 percent on a monthly basis since January 1997, after average discrepancies of almost 16 percent in 1996.** Discrepancies in monthly prices for 1996 were caused by major macroeconomic fluctuations that affected Mexico's gas markets. By early 1997, competitive forces had reasserted themselves and prices again moved in tandem. The strong price correlation between the border and the U.S. wellhead markets is indicative of the increasing integration of gas markets across North America.

- **While U.S. natural gas exports to Mexico fell from a high of 96 Bcf in 1992 to a recent low of 34 Bcf in 1996, export volumes have increased since and reached an estimated 50 Bcf in 1998.** If the turnaround continues, it is possible that several postponed proposals to expand capacity would proceed. At least six projects (totaling about 1.4 Bcf per day) are awaiting regulatory approval or improvements in market conditions. In 1998, daily utilization rates averaged about 12 percent of the beginning-of-year export capacity between the United States and Mexico, which totaled 1.1 Bcf per day. Mexican imports of U.S. gas of 50 Bcf in 1998 are 31 percent greater than during 1997 (Figure 7).

- **After several years of almost no activity, U.S. imports of Mexican gas have risen slowly but steadily since December 1993.** While recent U.S. import volumes represent the equivalent of less than 0.5 percent of the gas consumed in Texas alone, the 18.5 Bcf in 1998 is almost triple the 6.7 Bcf in 1995. The 1998 volume represented only about 13 percent of available capacity at the border. Energy officials from Petroleos Mexicanos (PEMEX), the state-owned Mexican national energy company, indicated that they could have exported more but could not find shipping capacity available on the U.S. side of the border. This problem could have been due at least in part to PEMEX's inexperience with acquiring rights to capacity in the new U.S. open-access marketplace. U.S. imports of Mexican gas in 1998 are 7 percent above the 17.2 Bcf recorded in 1997.

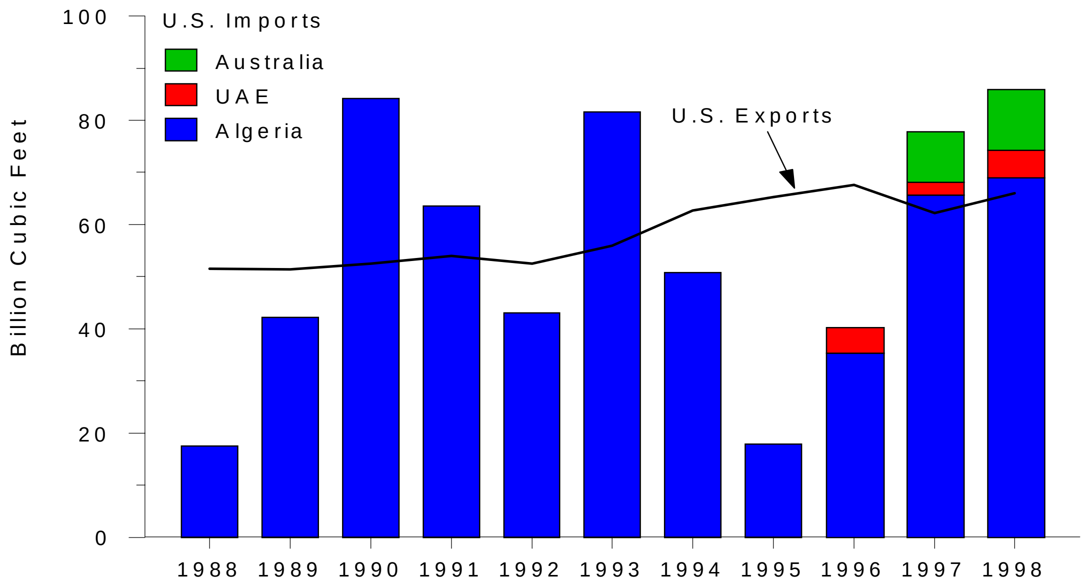
- **Exports of U.S. natural gas to Mexico primarily provide supplies to manufacturing/service industries and a growing number of electric generating plants in the northern states of Mexico.** Despite the substantial indigenous gas resources further south in Mexico, these northern states can be served most efficiently from the readily available supplies on the U.S. system. The largest export volume location since 1995 is adjacent to El Paso, Texas (Chihuahua State), about 40 percent of total exports (Figure 7). This figure is expected to grow significantly with the completion of El Paso Energy Company's Samalayucca project (212 million cubic feet (MMcf) per day). While the line initially transported only about 70 MMcf per day, it is expected to become fully utilized in 1999 with the completion of an electric generating plant in Chihuahua State.

- **Since 1996, Mexico's national energy regulatory agency, the Comisión Reguladora de Energía (CRE), has approved projects in at least 10 Mexican states or districts to improve the distribution of natural gas to residents and industries.** Most of these projects are joint ventures, often with one or more U.S. energy companies representing a major, although not a controlling, interest. As Mexico expands its efforts to privatize, or at least relax its regulatory control over the gas distribution infrastructure, it is likely that more such ventures will develop, which would increase gas demand.

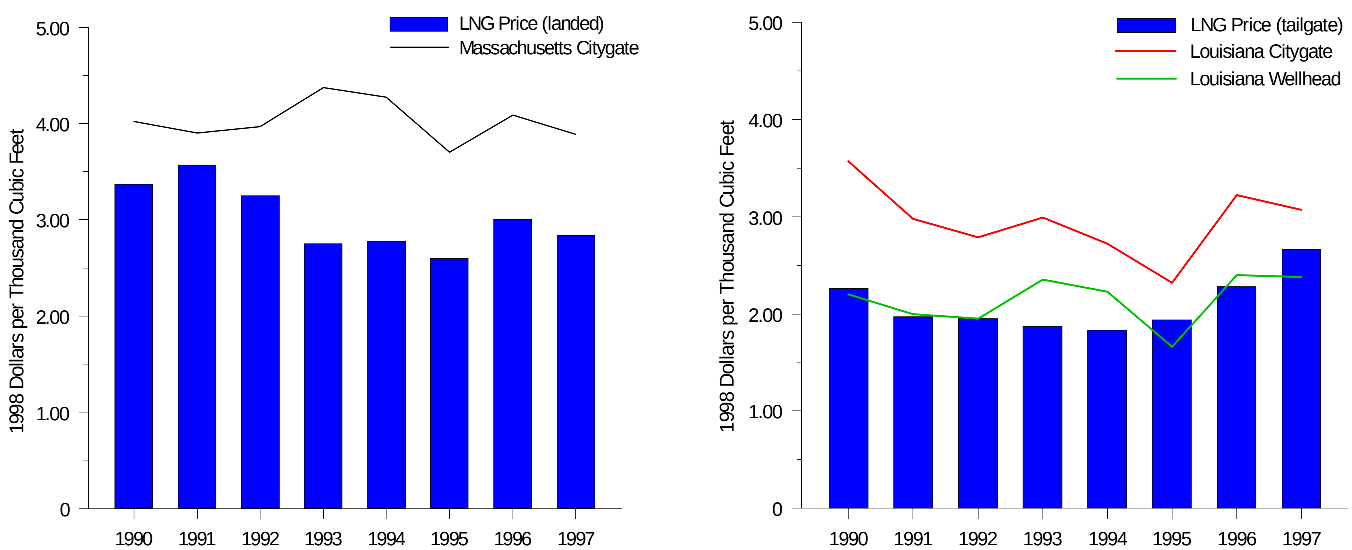
Mexico holds substantial promise for expansion on both the demand and supply sides of the market, although the short-term prospects for increased domestic production have become more uncertain as low oil prices in 1998 have forced spending cutbacks, affecting gas field development. Despite Mexico's endowment of natural gas resources of an estimated 70 trillion cubic feet in reserves with an additional 180 trillion cubic feet in remaining undiscovered recoverable gas resources, it likely will remain an active purchaser of U.S. gas supplies owing to the transportation logistics in each country. Thus, the future of Mexico's gas markets and that of U.S. markets along the southern border likely will continue to become increasingly interwoven.

## Figure 8. Liquefied Natural Gas (LNG) Provides the United States With Access to Global Markets

***The UAE and Australia have recently entered U.S. markets through spot transactions***




***LNG import prices are competitive with local supplies in both Massachusetts and Louisiana***




UAE = United Arab Emirates.

Notes: LNG prices in Louisiana are measured at the "tailgate," where the gas has been regasified. LNG prices in Massachusetts are on a "landed" basis, so the gas is still in liquid form. Regasification costs vary widely depending on numerous factors including throughput, but representative values of $0.26-$0.46 per thousand cubic feet may be used for reference. This range is based on information provided in *The Potential for Natural Gas in the United States: Source and Supply*, National Petroleum Council, Volume II, Appendix F (December 1992).

Sources: Energy Information Administration (EIA). **LNG Import Volumes:** 1988-1997—*Natural Gas Monthly*, Table SR4 (August 1998). 1998—Office of Fossil Energy. **LNG Export Volumes:** 1988-1997—*Natural Gas Monthly*, Table SR5 (August 1998). 1998—*Natural Gas Monthly* (February 1999). **LNG Import Prices, Citygate Prices, and Wellhead Prices:** *Natural Gas Annual* (various issues).

# Foreign Trade—Liquefied Natural Gas

The United States has been importing increasing volumes of liquefied natural gas (LNG), exceeding 85 billion cubic feet (Bcf) in 1998, compared with 18 Bcf in 1995. In 1998, LNG accounted for 2.7 percent of all U.S. natural gas imports (double the 1996 share), although less than 1 percent of total U.S. gas consumption. LNG imports are shipped to the United States via ocean-going tankers from Algeria, the United Arab Emirates (UAE), and Australia. U.S. LNG exports, from south Alaska to Japan, compete primarily with higher-priced petroleum liquids and thus command a higher price than U.S. LNG imports; from 1992 through 1997, the export price on average was 41 percent above the import price.

- **LNG imports into the United States have increased significantly since 1986-87, when they were suspended because of a contract dispute with Algeria.** They reached relative peaks of 84 and 82 Bcf in 1990 and 1993, then dropped to only 18 Bcf in 1995 while liquefaction facilities in Algeria were being refurbished. As liquefaction capacity was restored and supplies from the UAE and Australia became available, LNG imports to the United States resumed with steady growth, reaching slightly more than 85 Bcf in 1998. One reason for the increase has been the competitive LNG import prices relative to domestic prices (Figure 8).

- **The amount of LNG exported by the United States tends to be quite stable, being generally constrained to the level of available liquefaction capacity in south Alaska**. From 1995 through 1998, LNG exports from Alaska averaged roughly 65 Bcf annually. Despite the economic downturn affecting much of Asia, LNG exports from the United States remained fairly strong in 1998, rising 6 percent to 66.0 Bcf (Figure 8).

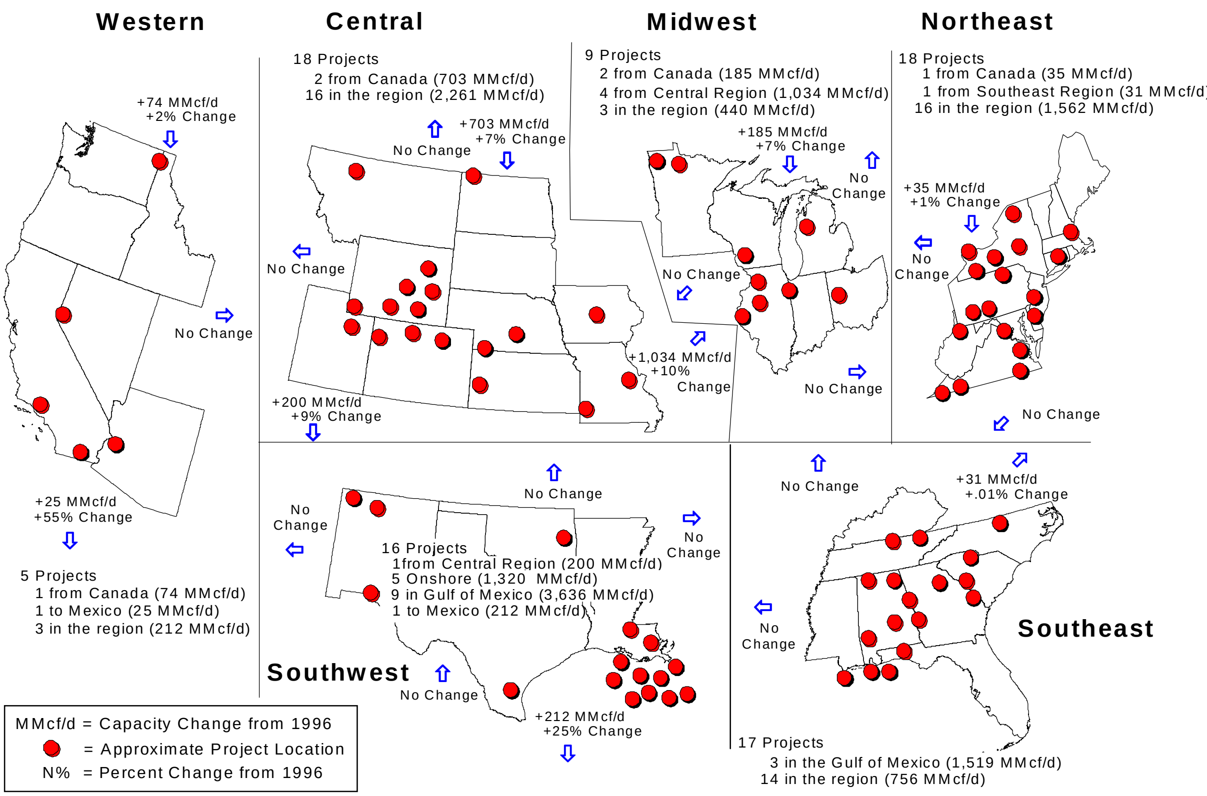
- **U.S. LNG imports can continue expanding for many years, based on current capacity and planned expansion.** LNG imports serve as supplemental gas supplies for regional systems. In Massachusetts, LNG imports comprise the equivalent of about 12 percent of the State's natural gas consumption, based on deliveries to all consumers of 378 Bcf in 1997. The LNG received at Lake Charles, Louisiana (almost 43 Bcf in 1998) is sold almost entirely to Florida Power and Light as fuel for electric generation. A third facility at Cove Point, Maryland, is currently operating as a peak-service storage facility using gas received from the transmission network, although reopening for importation is being considered. A fourth U.S. facility designed for LNG importation is located at Elba Island, Georgia, but it is not operational and there are no plans at present for it to reopen. Although each of these sites has substantial unused capacity, the Massachusetts facility is expected to expand its regasification capacity by 50 percent to 450 million cubic feet (MMcf) per day in early 1999.

- **The economic difficulties in many countries of Asia have altered the relative supply and demand balances for global LNG trade.** The macroeconomic difficulties in eastern Asia have resulted in reduced demand for energy in general and LNG in particular. The net impact of these difficulties will depend greatly on Japan, which consumed about 57 percent of LNG worldwide in 1997. Korea, the second largest purchaser of LNG, reduced imports in the first quarter of 1998 by 17.5 percent compared with the first quarter of 1997. Korea Gas (Kogas) has both canceled planned purchases and delayed purchases of 770 million tons, equivalent to 36 Bcf.[24] Concern about future market conditions has led to the suspension of a number of proposed projects, including development off Natuna Island in Indonesia (46 trillion cubic feet in reserves) and a 450-MMcf-per-day export project in western Canada, which was scheduled to start operation in late 1999.

- **In 1998, U.S. importers received eight LNG cargoes that were purchased under spot sales.** The presence of a spot market is a substantial development in global LNG trade, as it promotes a more dynamic system that can be a very important element in the resolution of current trading difficulties precipitated by the Asian economic crisis. LNG trade has been conducted primarily on the basis of direct, long-term arrangements between a supplier and particular customers. The spot market provides LNG suppliers holding excess fuel the opportunity to reach interested buyers. Current surpluses are expected to produce lower prices than otherwise, which may stimulate additional or new market penetration by LNG. Expanded trade under short- or long-term arrangements will be promoted with the 7 new tankers placed in service at the end of 1997, bringing the total to 103. This is 45 percent more than the 71 in 1991.

- **Further growth in global LNG trade is expected as Asian economies recover.** LNG's attractiveness as a fuel of choice is indicated by the fact that global LNG trade increased more than 2 percent in 1997 despite pipeline exports being virtually unchanged. Additional liquefaction projects are expected to begin operations in the next few years, adding to potential market growth. These projects include the Atlantic LNG Co. plant (400 MMcf per day) in Trinidad and Tobago, and the Bonny LNG project in Nigeria (425 MMcf per day), both expected to begin LNG shipments by the end of 1999.

## Figure 9. More Than 80 Natural Gas Pipeline Projects Were Completed Between January 1997 and December 1998




*. . . Adding 2.5 billion cubic feet per day to interregional interstate pipeline capacity*

**Interregional Natural Gas Pipeline Capacity as of December 31, 1998**

| Receiving Region | Sending Region[a] (Volumes in Million Cubic Feet per Day) | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| | Central | Midwest | Northeast | Southeast | Southwest | Western | Canada | Mexico | Total Entering Capacity |
| Central | -- | 2,354 | -- | -- | 8,609 | 298 | 2,266* | -- | 13,527 |
| Midwest | 10,913* | -- | 2,038 | 9,821 | -- | -- | 3,234* | | 26,006 |
| Northeast | -- | 4,887 | -- | 5,180* | -- | -- | 2,428* | -- | 12,495 |
| Southeast | -- | -- | 520 | -- | 20,846 | -- | -- | -- | 21,366 |
| Southwest | 2,314* | -- | -- | 405 | -- | -- | -- | 350 | 3,069 |
| Western | 1,194 | -- | -- | -- | 5,351 | -- | 3,860* | -- | 10,405 |
| Canada | 66 | 2,543 | -- | -- | -- | -- | -- | -- | 2,609 |
| Mexico | -- | -- | -- | -- | 1,056* | 70* | -- | -- | 1,126 |
| **Total Exiting Capacity** | **14,487** | **9,784** | **2,558** | **15,406** | **35,862** | **368** | **11,788** | **350** | **--** |

[a]Includes only the sum of capacity levels for the States and Canadian Provinces bounding the respective region.
*Includes increase in capacity since 1996.
MMcf/d = Million cubic feet per day. -- = Not applicable.
Sources: Energy Information Administration (EIA), EIAGIS-NG Geographic Information System: Natural Gas PipelineConstruction Database through December 1998; Natural Gas State Border Capacity Database (preliminary 1998).

# Interstate Pipeline Capacity

During 1997 and 1998, the interstate natural gas pipeline network in the United States experienced more upgrades and installation of new pipeline capacity than occurred in most of the previous 6 years. The completion of more than 80 projects (Figure 9) during these 2 years resulted in 14.2 billion cubic feet (Bcf) of new daily deliverability being added to the national network. Of this, 6.8 Bcf per day represented expansions to existing facilities and the rest installation of new pipeline routes. The largest amount of new capacity (5.4 Bcf per day, 16 projects) and new pipeline development was in the Southwest, where 9 new systems were completed, 4 of which were 600 million cubic feet (MMcf) per day or larger. Nationally, 13 projects (totaling about 2.6 Bcf per day) that were originally scheduled to be completed in 1998 were postponed until 1999, and another 4 were canceled mainly because of changed market conditions.

Yet only about 18 percent (2.5 Bcf per day) of this new pipeline capacity directly increased interregional transmission capacity. Compared with 1990 through 1996, when interregional capacity grew by about 15 percent (2.5 percent annually), additions between regions during 1997 and 1998 resulted in an increase of less than 1.5 percent.[25] This trend reflects the recent emphasis on improving and expanding pipeline service within the region and/or increasing access to new or expanding production facilities.

- **With the completion of nine separate projects associated with the expanding production areas of Wyoming and Montana, producers in the area can reach customers in the Midwest**, in addition to their traditional markets in the Western Region. These projects, including the new Pony Express project (KN Interstate Pipeline, 250 MMcf per day) and Trailblazer System expansion (190 MMcf per day), helped relieve an eastward capacity constraint problem that had existed in the Rocky Mountain area for several years.

- **Another capacity-constrained production area, the San Juan Basin of New Mexico, experienced some relief in 1997 and 1998 with the completion of several key projects.** The two major pipeline transporters operating in the basin, Transwestern Pipeline and El Paso Natural Gas Company, completed projects that improved deliverability out of the basin (mostly through increased compression) by about 400 MMcf per day. Several additional projects were approved, which would bring pipeline capacity more in line with productive capacity in the area. In mid-1997, El Paso completed its Havasu Crossover expansion project. This project expanded capacity on the westward-bound portion of the system to move supplies that are redirected eastward (either physically or by displacement) just east of the California border. This increased El Paso's deliverability in the Waha area of west Texas by an additional 180 MMcf per day.

- **During 1997 and 1998, 12 natural gas pipeline projects were completed in the Gulf of Mexico, representing a total of 5.2 Bcf per day of new pipeline capacity.** Seven of these projects now bring an additional 3.6 Bcf per day to onshore Louisiana; the others are gathering systems linking producing platforms in the Gulf with mainlines directed to onshore facilities. The largest of the lines to onshore Louisiana were three new pipelines: the Destin Pipeline (1 Bcf per day) and the Nautilus and Discovery, each representing 600 MMcf per day of new capacity.

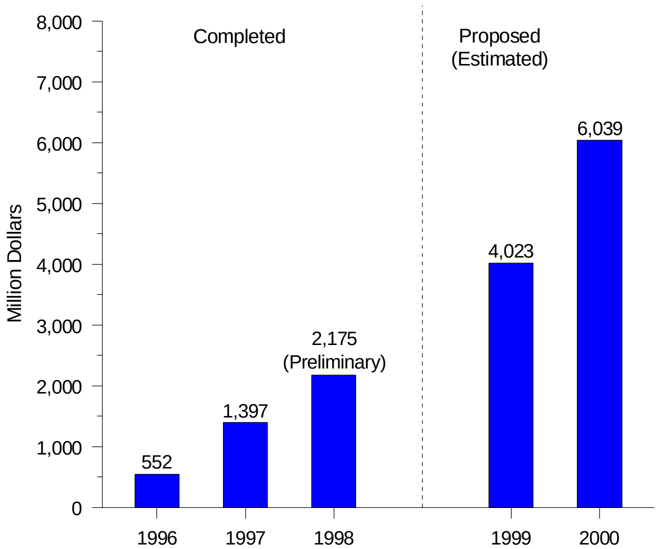
- **After expanding by more than 69 percent between 1990 and 1996, very little new import capacity from Canada was added in 1997 and 1998.** The largest addition, 700 MMcf per day, was the Northern Border Pipeline expansion, which began service in December 1998. Only one expansion project, Viking Gas Transmission Company (60 MMcf per day), was placed in service during 1997, although TransCanada Pipeline Company increased capacity on its side of the border by a total of 170 MMcf per day (at four points: three in Quebec (to New York) and one to the Viking System in Minnesota).

- **Regional service improvements dominated in the Northeast and Southeast regions.** The majority of projects (30 of 35) and 59 percent of the new capacity added in these regions expanded existing pipeline deliverability to local customers in 1997 and 1998. In the Northeast, added service to underground storage sites and for storage customers along several major sections of mainline, accounted for nearly half of the capacity added during the period.

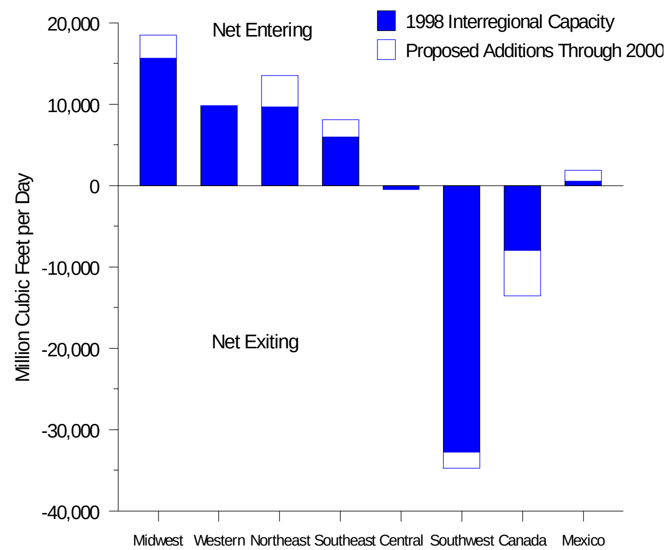
These past 2 years also saw the completion of new natural gas export lines to Mexico for the first time in 5 years. Installation of the two new export points, one from California (25 MMcf per day) and one from Texas (212 MMcf per day) increased U.S. natural gas export capabilities to Mexico by 27 percent. In the late 1980s, the Mexico market was expected to provide a major outlet for Southwest production. But the approval and execution of a number of early proposals has been slow, primarily because of regulatory delays and the smaller-than-expected growth in natural gas demand in northern Mexico.

# Figure 10. The Interstate Natural Gas Pipeline Network Is Expected To Grow Significantly Through 2000

***Annual pipeline investment could reach $6 billion in 2000 . . .***




***. . . Spurred by growing import capacity from Canada and Northeast expansions***




***Total added capacity in 1999 and 2000 could exceed 20 million cubic feet per day***

**Proposed Additions to Interstate Natural Gas Pipeline Capacity, 1999 and 2000**

| Proposed for Region | 1999 | | 2000 | | Total | | |
|---|---|---|---|---|---|---|---|
| | Number of Projects | Capacity Addition (MMcf/d) | Number of Projects | Capacity Addition (MMcf/d) | Number of Projects | Capacity Addition (MMcf/d) | Canadian Import Portion[a] (probable) |
| Central . . . . . . . . . . . | 4 | 910 | 5 | 1,330 | 9 | 2,240 | 253 |
| Midwest[b] . . . . . . . . . | 10 | 1,956 | 7 | 3,865 | 17 | 5,821 | 1,394 |
| Northeast . . . . . . . . . | 17 | 2,253 | 9 | 4,293 | 26 | 6,546 | 2,027 |
| Southeast . . . . . . . . | 5 | 1,161 | 1 | 200 | 6 | 1,361 | -- |
| Southwest[b] . . . . . . . | 10 | 3,099 | 2 | 398 | 12 | 3,497 | – |
| Western[b] . . . . . . . . . | 5 | 562 | 1 | 130 | 6 | 692 | 0 |
| U.S. Total . . . . . . . | 51 | 9,941 | 25 | 10,216 | 76 | 20,157 | 3,674 |
| Canada[c] . . . . . . . . . . | 4 | 1,564 | 3 | 2,675 | 7 | 4,239 | – |

[a]EIA estimate of how much import capacity will actually be built. Some proposals are competing for or are within the same markets, and therefore some may be consolidated, downsized, or canceled.

[b]Includes export projects to Mexico or Canada.

[c]Includes Canadian projects that may support expanded exports to the United States.

MMcf/d = Million cubic feet per day. -- = Not applicable.

Notes: Excludes projects on hold as of January 1999. In the table, a project that crosses interregional boundaries is included in the region in which it terminates.

Source: Energy Information Administration (EIA), EIAGIS-NG Geographic Information System, Natural Gas Pipeline Construction Database through December 1998.

# Potential Interstate Pipeline Capacity

The large annual increase in natural gas pipeline capacity expansions seen in 1998 should continue through the turn of the century. In 1998 alone, 47 pipeline expansion projects in the United States were completed and placed in service, adding more than 10 billion cubic feet (Bcf) per day of new capacity on the national pipeline grid. Moreover, a similar level of increase may occur in both 1999 and 2000.[26] The greatest amount of pipeline expansion activity is expected to occur in the Midwest and the Northeast regions as demand for greater Canadian export capabilities continues to grow. More than 3.7 Bcf per day of Canadian export capacity expansion has been proposed for completion during 1999 and 2000. For the most part, the proposals are driven by Canadian natural gas producers seeking markets for their expanding production capabilities.

- **Annual investments in pipeline expansions could reach the $6 billion level by 2000 (Figure 10) with the scheduled completion of several major new pipeline systems.** Among the largest will be the Alliance ($2.9 billion), Independence ($676 million), Millennium ($684 million) and Vector ($447 million) pipeline systems. After 2000, however, the level of additional investment is scheduled to drop off, as very few projects have been proposed whose inservice dates extend beyond the close of the decade.

- **Several new pipelines, as well as expansions to existing systems, will begin in western Canada and route supplies to the Chicago, Illinois, area.** But a sizable portion of gas delivered there will actually be destined for the Ontario, Canada, market and/or the U.S. Northeast. As much as 1.8 Bcf per day of new capacity is scheduled to reach the Chicago area by 2000. At least four pipeline systems (two of which are new), accounting for 3.2 Bcf per day, have been proposed to pick up Chicago area supplies and carry them eastward.

- **Construction of the first phase of the Maritimes and Northeast Pipeline began in 1998.** When finished in late 1999, the project will have the capability of bringing 440 Bcf per day of Sable Island gas (off Nova Scotia) directly to the New England marketplace. While it will account for only about 3 percent of total Canadian export capabilities to the United States, it represents the first major gas supply project off the east coast of North America and the first Canadian supply project in close proximity to New England markets.

- **The expanding deep-water development in the Gulf of Mexico will necessitate the building of additional new natural gas systems to bring the new production onshore.** At least two supporting natural gas gathering systems are slated for expansion in 1999 (about 349 million cubic feet (MMcf) per day). These systems will link expanding or new production deep-water platforms to several new offshore mainlines, which in turn will tie the new supply sources to onshore processing plants and interconnections with major interstate pipelines. The largest proposed deep-water project is the new Sea Star Pipeline (Koch Gateway Company, 600 MMcf per day), which, if approved, could link up with the interstate system in Louisiana by the end of 1999.

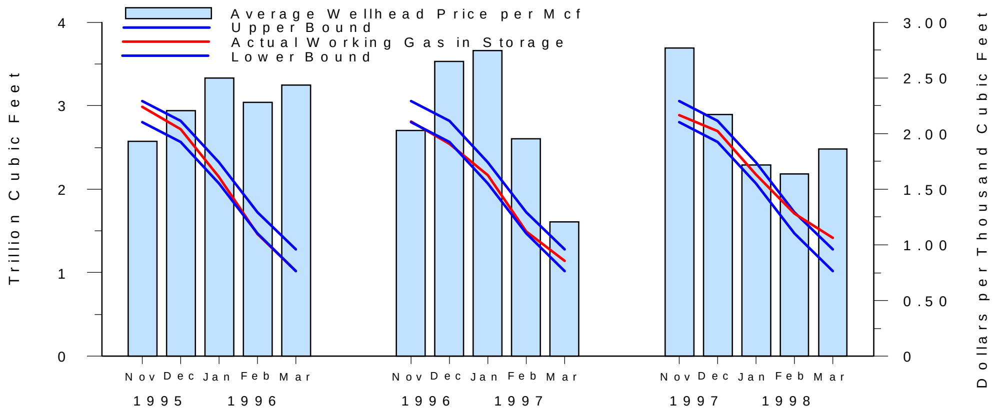
- The Southeast Region, which is adjacent to the growing Gulf Coast production and hosts most of the longhaul pipelines serving the Midwest and Northeast regions, will probably be the destination of a substantial portion of the new Gulf supplies. As new development in the Gulf of Mexico has moved to deeper waters and further eastward, the Southeast Region has also been experiencing a growing demand for natural gas. Several of the regional inter- and intrastate pipelines have announced plans for system expansions. Although not as large (in capacity) as the offshore projects, about 40 percent of the new capacity in the region (0.6 of 1.4 Bcf per day) is slated to serve local customers directly.

- **Pipeline expansions in the Western Region, while small in comparison with those in other regions, are unique in several respects.** First, Northwest Pipeline Company has plans to deliver Canadian-produced gas to the Vancouver, British Columbia, area via transshipments from Alberta, Canada, southward through PG&E Transmission-NW with interconnections to Northwest Pipeline in Washington State. This would be the first time natural gas would move back across the border in significant quantities in the West. Second, Colorado Interstate Gas has a proposed project that, for the first time, would institute gas deliveries to northern Nevada from fields located in the Powder River Basin of Wyoming.

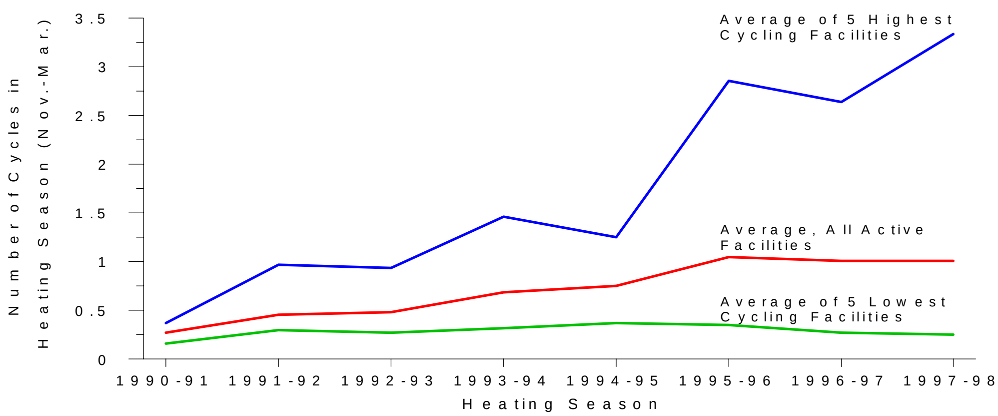
- **Several projects are scheduled for completion in 1999 that would increase export capacity to Mexico by 260 MMcf per day, 23 percent above the 1998 level.** The Tennessee Gas Pipeline's Reynosa project would deliver U.S. gas to the Petroleos Mexicanos (PEMEX) pipeline system in Mexico for delivery to the local distribution system in the state of Nuevo Leon. A second project, which would deliver supplies to industrial customers south of the Arizona border, would be installed by El Paso Energy and connected to a new 65-mile pipeline being built within Mexico by Mexcobre Pipeline.

## Figure 11. Underground Storage Operations Are Crucial to Meeting Seasonal Customer Demands

### *As stocks move below normal ranges, prices generally move up*




### *Cycling rates increased sharply at some salt cavern facilities in recent winters but on average showed no growth*




### *The Midwest and Southwest regions have the most storage capacity*

| | Aquifer | | | Depleted Gas/Oil Field | | | Salt Cavern | | | Total | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Region | Number of Facilities | Working Gas Capacity (Bcf) | Deliverability (MMcf/day) | Number of Facilities | Working Gas Capacity (Bcf) | Deliverability (MMcf/day) | Number of Facilities | Working Gas Capacity (Bcf) | Deliverability (MMcf/day) | Number of Facilities | Working Gas Capacity (Bcf) | Deliverability (MMcf/day) |
| Central | 8 | 98.2 | 1,565 | 40 | 473.3 | 4,534 | 1 | 2.1 | 160 | 49 | 573.7 | 6,259 |
| Midwest | 28 | 224.9 | 6,091 | 98 | 870.3 | 17,649 | 2 | 2.1 | 78 | 128 | 1,097.3 | 23,818 |
| Northeast | 0 | 0.0 | 0 | 119 | 710.5 | 11,799 | 2 | 1.8 | 185 | 121 | 712.3 | 11,984 |
| Southeast | 2 | 6.0 | 67 | 27 | 145.1 | 2,722 | 4 | 22.6 | 2,430 | 33 | 173.8 | 5,220 |
| Southwest | 1 | 8.3 | 10 | 48 | 886.7 | 12,458 | 18 | 92.8 | 9,033 | 67 | 987.8 | 21,501 |
| West | 1 | 15.2 | 550 | 11 | 162.9 | 6,590 | 0 | 0.0 | 0 | 12 | 178.1 | 7,140 |
| **Total** | **40** | **352.6** | **8,283** | **343** | **3,249.1** | **55,755** | **27** | **121.6** | **11,886** | **410** | **3,723.5** | **75,925** |

Bcf = Billion cubic feet. MMcf/day = Million cubic feet per day.

Note: The regions in the table conform to those shown in the map on page 24.

Sources: Energy Information Administration (EIA), Office of Oil and Gas. **Working Gas Inventories and Capacities:** EIA, Form EIA-191 "Monthly Underground Gas Storage Report" and EIAGIS Geographic Information System, Existing Underground Storage Database as of December 1998. **Wellhead Prices:** EIA, *Natural Gas Monthly* (February 1999).

# Storage Operations

At the end of the first month of the 1998-99 heating season, working gas inventories stood at 3,143 billion cubic feet (Bcf), the highest level for November 30 since 1990 and 16 percent more than last year. Storage stocks have been at unusually high levels since last winter, when warmer-than-normal temperatures prevailed across most of the Lower 48 States.[27] Working gas inventories at the end of the 1997-98 heating season were 1,184 Bcf, or 17 percent greater than the average for the preceding 5 years for that point in the year. The refill season was quite robust, reinforced by low prices, moderate demand, no significant supply disruptions, and apparent expectations of normally cold temperatures in the upcoming winter. By the start of the 1998-99 heating season, storage stocks were 3,172 Bcf, the highest level since 1992 and only the third time in this decade that inventories were above the 3,100 mark.

- **Between February and December 1998, stock levels exceeded the seasonally adjusted normal range[28] in every month but one.** Since the implementation of Order 636 in November 1993, it appears that inventories are being managed more efficiently by operators and their customers. As one indication, monthly average storage levels over the past 6 years (1992-1997) have generally shifted downward compared with the previous 6 years (1986-1991). However, 1998 ran counter to this trend. Beginning with May end-of-month inventories, 1998 monthly levels were the highest of the past 6 years, and were consistently above the seasonally-adjusted normal range from March through December. Although stocks were at their second-lowest level in the past 6 years entering the 1997-98 heating season, the mild winter, with a particularly warm January, left stock levels at the end of March at their second-highest level in the past 6 years. From this point, net injections were strong, boosting inventories above the upper bound of the normal range.

- **In the past three heating seasons, signs of upward pressure on wellhead prices have appeared when inventories fall below a "normal" range** (Figure 11). In 1995-96, ample storage levels early in the season served to limit price increases in the wellhead markets until storage levels later fell relative to normal. In 1996-97, working gas storage levels were relatively low as the heating season began because of generally higher wellhead gas prices during the 1996 refill season in combination with low futures prices for the upcoming heating season. The lessened supplies available to the market throughout the heating season resulted in a price surge, which only diminished as weather warmed. Yet a third scenario was played out in 1997-98. Storage levels began the heating season at close to the mid point of normal, yet wellhead prices were relatively high from the middle of the year into November. Limited demand owing to the El Ninó-driven warm winter and the ample supplies in storage led to declining prices through most of the heating season. The relative gas abundance signaled by the low prices led to low storage withdrawals, leaving a hefty inventory balance at the end of March 1998.

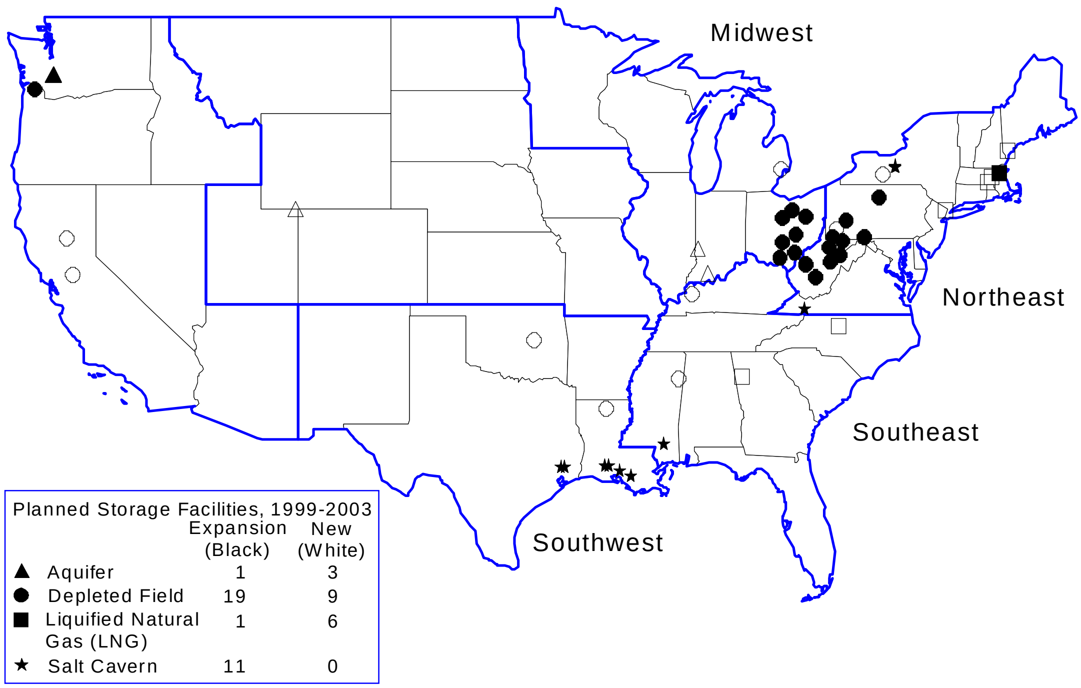
- **Salt cavern storage utilization dropped slightly in the past two heating seasons.** The average heating-season cycling rate for salt cavern storage facilities had increased every year between 1990 and 1996, quadrupling from 0.27 to 1.05 (Figure 11). However, the rate dropped slightly for the 1996-97 heating season and remained flat during the 1997-98 heating season. Warmer-than-normal temperatures, with fewer and less extreme episodes of frigid temperatures, contributed to the lower utilization of salt cavern storage in these two heating seasons. Further, decreasing price volatility (see Figure 3, p. 6) has likely meant fewer or less potentially profitable arbitrage opportunities, further reducing usage of high-cycle storage capacity. Still, contrasting with the overall average for salt cavern facilities,[29] average utilization of the top five (by cycle rate) facilities increased by 27 percent to over 3 cycles per heating season (2.64 to 3.34).

- **A large number of storage facilities appear to be inactive.** Of the 410 facilities included in the EIA-191 monthly survey, "Underground Gas Storage Report," 38 facilities have had either no activity whatsoever, or withdrawals of gas only, for at least the past 2 years. These fields comprise about 107 Bcf of working gas capacity and 824 MMcf per day of deliverability, or about 3 and 1 percent, respectively, of national totals as of November 1, 1998. The largest amounts of inactive capacity are in the Southwest and Midwest regions (71 and 21 Bcf of working gas capacity, respectively, and 485 and 219 MMcf per day of deliverability).[30]

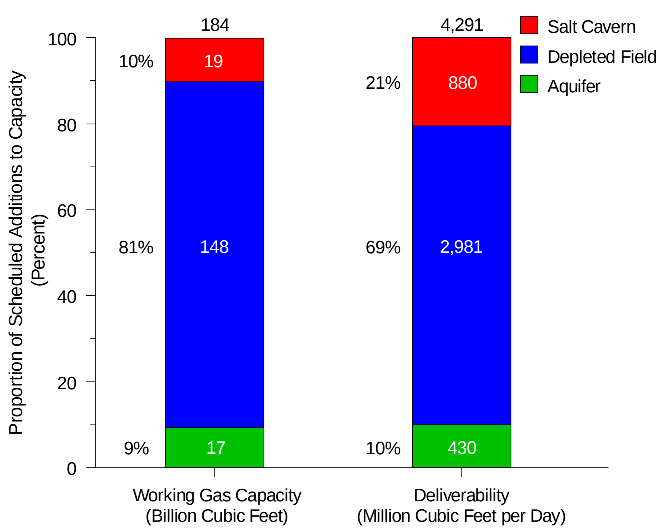
- **The Midwest and Southwest regions together comprise 56 percent of working gas capacity and nearly 60 percent of deliverability** (Figure 11). Though similar in terms of capacities, the two regions are very different with respect to storage asset profiles and utilization. Midwest storage is primarily market area storage, while much of the storage in the Southwest is an adjunct of production. Average per-facility working gas capacity and deliverability for the Southwest is over 60 percent greater than for the Midwest, largely because of the preponderance of high-deliverability storage and relatively large depleted fields in the Southwest.

## Figure 12. Interest in Storage Development Has Slowed But 50 Projects Are Planned Between 1999 and 2003

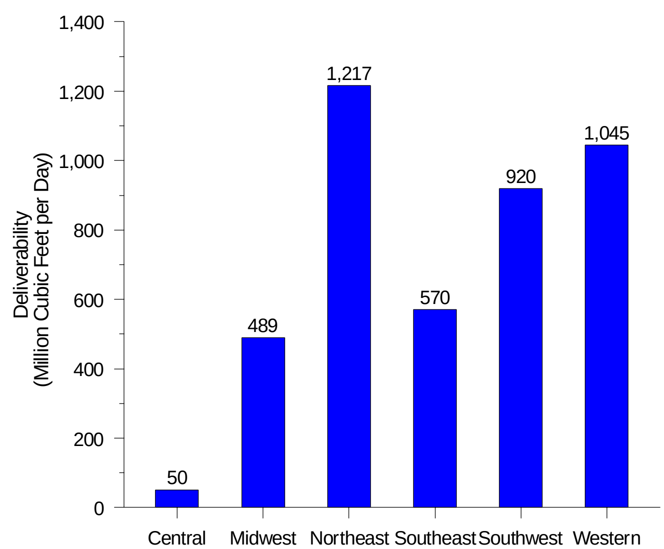
***Over half of the scheduled projects are in the Midwest and Northeast***




***As with existing capacity, traditional depleted-reservoir storage is the largest source of new capacity***




***The Northeast is slated for the largest amount of new deliverability***




Source: Energy Information Administration (EIA), EIAGIS-NG Geographic Information System, Proposed Underground Natural Gas Storage Database, as of December 1998.

## Storage Development

Twenty-two storage-facility expansion projects were completed in time for the beginning of the 1998-99 heating season. These projects added more than 28 billion cubic feet (Bcf) of working gas capacity and 1,120 million cubic feet (MMcf) per day of storage deliverability.[31] Still, as of November 1, 1998, and taking into account capacity adjustments at existing facilities that were reported to the Energy Information Administration, working gas capacity was 43 Bcf less (just over 1 percent) than the year-earlier level of 3,767 Bcf, although daily deliverability increased by 1,346 MMcf (almost 2 percent) from 74,579.[32] Interest in storage development has slowed substantially during the past 2 years. Since July 1997, only 19 storage development projects have been proposed.[33] These are offset by the attrition of previously announced projects; 10 of which have been canceled outright, while another 15 are on hold or inactive.

- **Since the decade's banner year of 1993, development of additional storage capacity has slowed.** In that year, about 103 Bcf of working gas capacity and nearly 4 Bcf per day of deliverability were added. The years since then have seen a significant drop in expansion activities. In 1996, only about 12 Bcf of working gas capacity and 680 MMcf per day of deliverability were added and, in 1997, only another 12 Bcf of working gas capacity and about 269 MMcf per day of deliverability.[34] During 1998, expansions were only marginally higher (see above).[35] The absence of new-facility development suggests that few clearly profitable sites currently exist. The industry is likely to continue to focus primarily on expansions of proven facilities (Figure 12), unless demand or prices grow sharply or a breakthrough in storage technology is achieved.

- **The development slowdown includes salt cavern storage.** Of the six proposed new salt cavern storage facilities as of 1997, none has been realized to date. Three have been canceled and three are currently on "hold." One project that once appeared attractive was the Avoca site in southeastern New York. Avoca was one of only four salt cavern storage facilities either planned for or in operation in the Northeast. Plagued by brine disposal problems, the project filed for bankruptcy in July 1997. Another Northeast project involved CNG's plan to lease salt caverns formerly used for petroleum liquids storage by Bath Petroleum Storage. However, the idea was dropped when the Federal Energy Regulatory Commission (FERC) ruled that the proposal violated pertinent regulations. What once may have been the most promising of potential new salt cavern facilities is the Tioga project in Pennsylvania. Although approved by FERC, it has been stalled owing to legal interventions by other parties.[36] While recent reports indicate that the opposing parties may be nearing a resolution, the project was still on hold in early 1999.

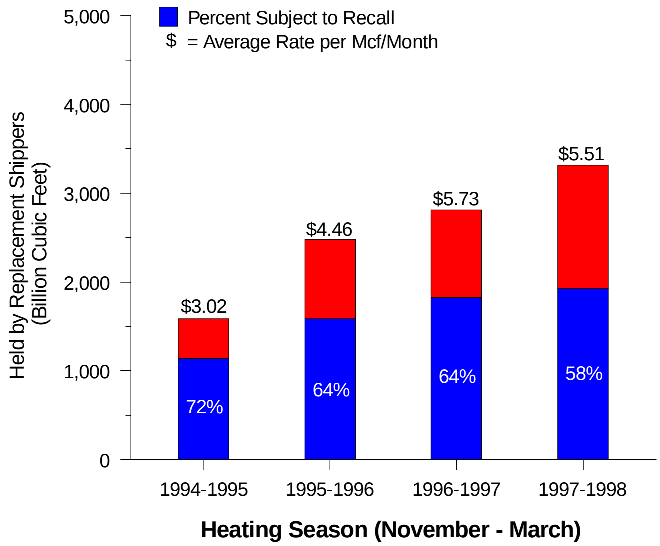
- **Interest continues in developing alternative methods for high-deliverability peaking service.** High deliverability is most often associated with salt-cavern storage facilities, whose share of currently-scheduled deliverability additions (Figure 12) is out of proportion to the relatively small number of sites or their total share of working gas capacity. Nonetheless, suitable sites for salt cavern development are limited, particularly near the expanding market areas along the Eastern Seaboard. This limitation may help explain an apparent growing interest in liquefied natural gas (LNG) projects. Although high deliverability has always been a characteristic of LNG facilities, as recently as 1997 only four LNG storage projects were planned. Since then, at least five additional projects have been proposed, with three of them in the Northeast.[37] The newer facilities are being designed and built with larger capacities; many can sustain deliverability rates for as long as 10 days, which is comparable to salt cavern performance (albeit with much smaller capacities). Though a relatively expensive source of supply, high deliverability and the ability to cycle LNG capacity multiple times in a given season make it an excellent peaking supply source while helping to lower the per-unit cost of operations.

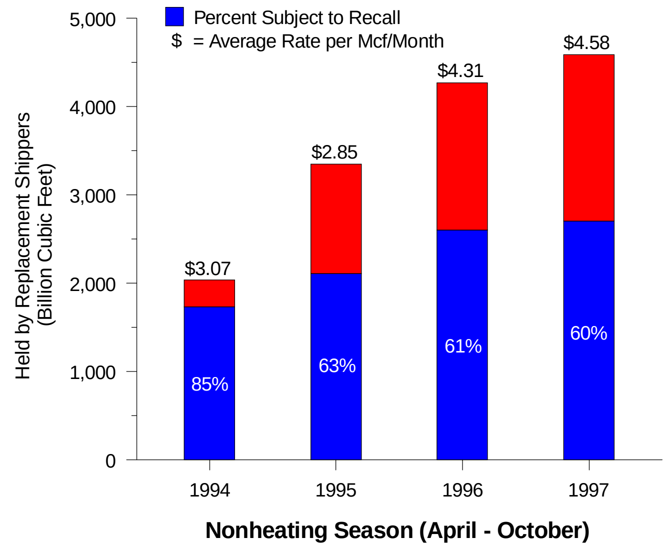
- **Horizontal wells in depleted-reservoir storage may be another high-deliverability alternative.** Horizontal drilling is not a new technology (it has been used extensively in exploration and production applications), but its application to enhance the performance of reservoir storage is still somewhat experimental.[38] To date, only a few companies have used horizontal drilling at storage facilities and with mixed results.[39] However, there have been some instances that were quite successful. At least one storage company is currently working on applying this technology at a site in Pennsylvania and is also scouting other potential sites in the Northeast .

As of November 1998, 50 storage projects are scheduled through 2003 (Figure 12). If all were implemented as proposed, working gas capacity would increase by close to 5 percent to approximately 3,908 Bcf, and deliverability would increase by more than 5 percent to over 80 Bcf per day. The Northeast, with high concentrations of gas consumers and significant wintertime swing demand, ranks first in planned additions to deliverability at about 1.2 Bcf per day, or almost 30 percent of scheduled deliverability additions.

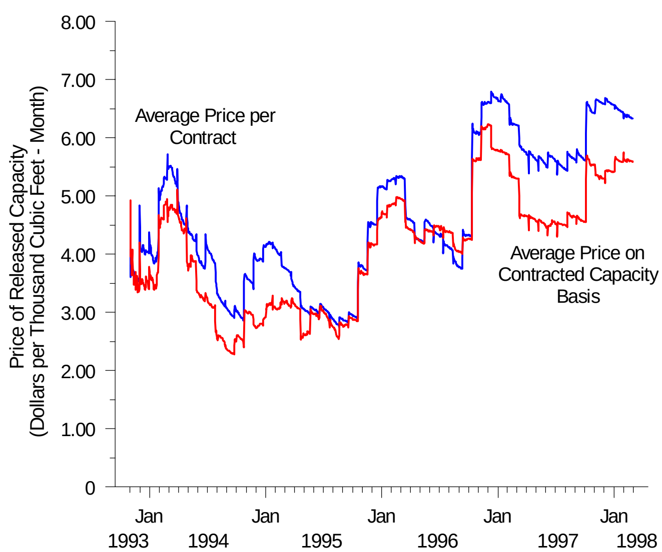
## Figure 13. The Capacity Release Market Appears To Be a Reliable Source for Transportation Capacity

***The release market has witnessed significant seasonal growth***

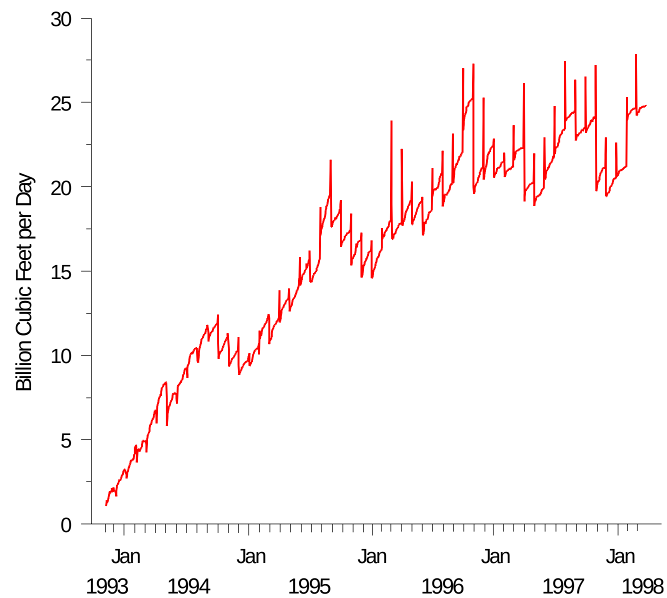



***Prices for released capacity continue to increase***




***The release market may be maturing***




Mcf/Month = Thousand cubic feet per month.

Sources: Energy Information Administration, Office of Oil and Gas, derived from: **November 1993 - July 1994:** Pasha Publications, Inc. **July 1994 - March 1998:** Federal Energy Regulatory Commission, Electronic Data Interchange (EDI) data.

# Capacity Release

In today's competitive natural gas market with increased marketer presence and a demand for flexibility in contracting, capacity release provides a mechanism for shippers to improve transportation flexibility and react more quickly to market changes. This mechanism became available to shippers with the Federal Energy Regulatory Commission (FERC) implementation of Order 636 in 1993, which gave firm transportation contract holders the right to sell all or part of their transportation capacity for any length of time during the contract. Over the period November 1993 through March 1998, capacity release saved releasing shippers up to $3.6 billion, or about 6 percent of the U.S. transportation revenues to interstate natural gas pipeline companies during the same period.

- **The capacity release market continues to grow but at a slower pace**. The amount of capacity held by replacement shippers grew between seasons and years from November 1993 through March 1998.[40] The most rapid growth occurred in the first few years under Order 636 with increases of 1 trillion cubic feet between each heating season from November 1993 through March 1996. The growth then slowed to about half that pace between the 1995-96 and 1997-98 heating seasons (Figure 13). The same general pattern of rapid growth followed by a slowdown was evident during the nonheating seasons 1994 through 1997. During the 12 months ending March 31, 1998, the capacity held by replacement shippers was 8.0 Tcf, or the equivalent of 40 percent of the gas delivered to U.S. markets during the same period.[41]

- **The evolution of trading mechanisms and standards since 1993 has made the release market easier to use.** In the early years of the release market, each pipeline company developed its own electronic nonstandardized bulletin board. The market has since moved to using the Internet with protocols established by the Gas Industry Standards Board.

- **Rates received by shippers for released capacity were discounted, on average, almost 70 percent below the maximum rate for 1995 through 1998.**[42] Discounts for the year ending March 31, 1998, averaged about 50 percent, considerably less than the average discount of about 90 percent for the comparable period in 1995. The total revenue generated by the capacity release market in the year ending March 31, 1998, is estimated at $1.3 billion or about 10 percent of the transportation revenues for 1997.

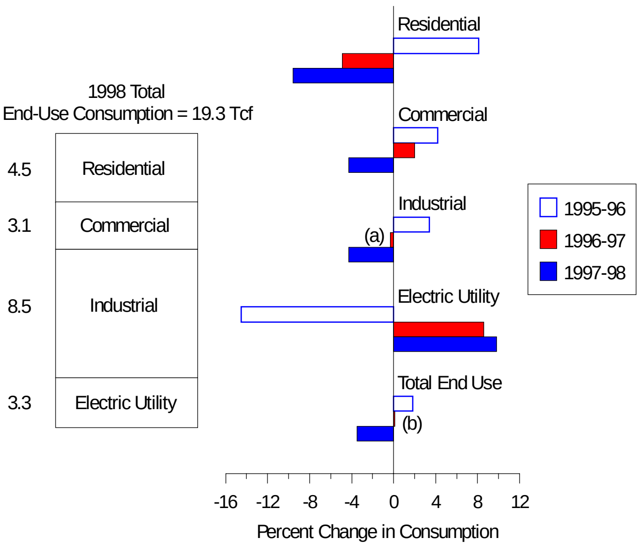
- **The price of released capacity has increased on both a per contract and a contracted capacity basis.** Between 1994 and 1998, the average price of released capacity measured across all active contracts increased by 61 percent, from $3.75 per thousand cubic feet (Mcf) per month during the 12 months ending March 31, 1995 (heating year 1995) to $6.04 in heating year 1998 (Figure 13).[43] Comparable rates on a contracted capacity basis, although lower than those averaged across contracts, increased from $3.05 to $4.97 per Mcf per month (63 percent) during the same period. The difference between the two price series is apparent particularly during the heating season when relatively small, higher-priced parcels of capacity are being traded on the release market.

- **The decline in the amount of capacity subject to recall and the increasing average price for released capacity from 1994 through 1998 may indicate that shippers perceive the release market as a reliable source for transportation capacity.** About 58 percent of the released capacity was subject to recall during the 1997-98 heating season (November through March), down from the 64 to 72 percent levels for the three previous heating seasons. At the same time, the amount of awarded released capacity increased by 18 percent between the 1996-97 and 1997-98 heating seasons. The decrease in recall provisions and the increase in awarded capacity between those two heating seasons may be the result of warmer-than-normal weather.[44] However, the general trend in recall provisions indicates that firm capacity holders are comfortable with unconditional release of capacity.

- **The leveling-off of capacity held by replacement shippers may indicate that the release market has matured** (Figure 13). As older, long-term contracts expire and new contracts more representative of current market conditions are put in place, there could be less capacity available for the release market. Market behavior during the 12 months ending March 1998 suggests that this may be happening. The slowdown in the growth rate of capacity released, coupled with a modest 2-percent growth in average price during the 12 months, suggests that the release market may be entering a phase of more stable operations without large, rapid shifts in market conditions. However, changes in market operations, such as the removal of the price cap, could draw new players to the market.

# Figure 14. End-Use Consumption in 1998 Fell 4 Percent from Its Record High in 1997

### *Only electric utilities increased consumption in 1998*

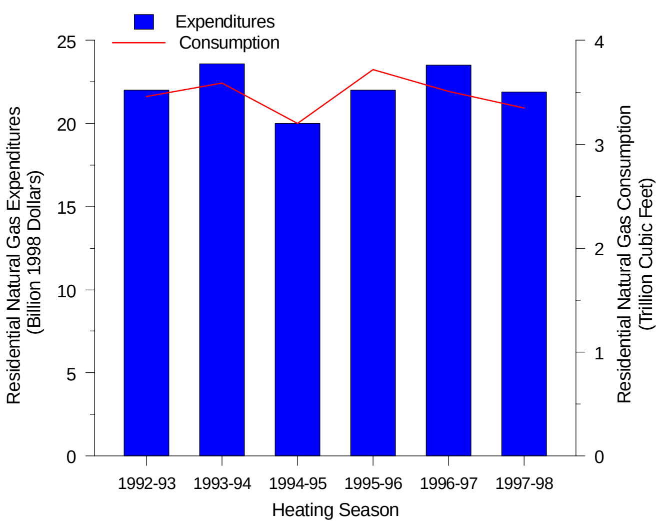



### *The residential price in 1997 caught up with wellhead price increases in 1996*

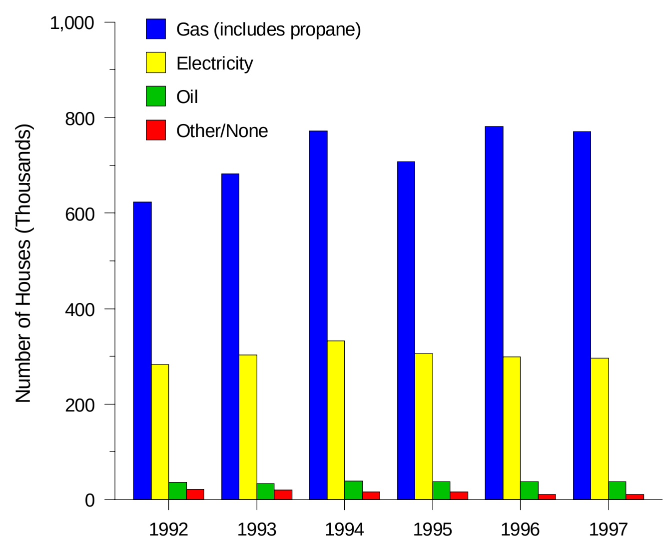
**Natural Gas Prices**
(1998 Dollars per Thousand Cubic Feet)

| Year | Well-head | City-gate | Resi-dential | Com-mer-cial | Indust-trial | Electric Utility |
|---|---|---|---|---|---|---|
| 1995 | 1.62 | 2.91 | 6.35 | 5.29 | 2.84 | 2.12 |
| 1996 | 2.23 | 3.44 | 6.52 | 5.56 | 3.52 | 2.77 |
| 1997 | 2.34 | 3.65 | 7.01 | 5.85 | 3.63 | 2.77 |
| | Change in Prices | | | | | |
| 1995-96 | 0.61 | 0.52 | 0.17 | 0.26 | 0.68 | 0.65 |
| 1996-97 | 0.11 | 0.21 | 0.49 | 0.29 | 0.11 | 0.00 |
| | Percentage Change in Prices | | | | | |
| 1995-96 | 37.4 | 17.9 | 2.7 | 4.9 | 23.9 | 30.7 |
| 1996-97 | 5.0 | 6.1 | 7.5 | 5.3 | 3.1 | 0.0 |

### *Residential users paid more but consumed less in the 1996-97 heating season*




### *Gas heats most new single-family houses*




(a) Industrial consumption declined 0.3 percent from 1996 to 1997.
(b) Total end-use consumption rose 0.1 percent from 1996 to 1997.
Tcf = Trillion cubic feet.

Notes: Sum of end-use consumption does not equal the total because of independent rounding. End-use prices for all but the electric utility sector are for onsystem sales only. The heating season is from November through March.

Sources: Energy Information Administration (EIA), Office of Oil and Gas. **Consumption, Prices, and Expenditures:** derived from EIA, *Natural Gas Monthly*, various issues and Chain-Type Price Indices for Gross Domestic Product from U.S. Department of Commerce, Bureau of Economic Analysis. **New Housing:** U.S. Department of Commerce, Bureau of the Census, *Characteristics of New Housing*, 1996 and 1997.

# End-Use Consumption and Price

End-use natural gas consumption is estimated to have been 19.3 trillion cubic feet (Tcf) in 1998. This is 4 percent lower than in 1997, but consumption in both 1997 and 1996 had set all-time records at just over 20.0 Tcf.[45] The largest decline in 1998, in both quantity and percentage terms, occurred in the residential sector. Residential consumption in 1998 is estimated to have been 4.5 Tcf, 477 billion cubic feet, or 10 percent, lower than in 1997 (Figure 14). The decline can be attributed to milder weather in 1998 resulting in part from the El Niño event in the Pacific.[46] Warmer temperatures reduced the demand for natural gas for space heating, the major use of natural gas in both the residential and commercial sectors. Natural gas consumption in the commercial sector in 1998 is estimated to have been 3.1 Tcf, 4 percent lower than in 1997. The industrial sector saw the second-largest drop in natural gas consumption between 1997 and 1998, falling by 381 billion cubic feet, or 4 percent, to an estimated 8.5 Tcf.

The electric utility sector is the only sector that had an increase in natural gas consumption in 1998. Consumption for the full year 1998 is estimated to have been 3.3 Tcf, 10 percent above that of 1997. Extremely high summer temperatures in the Southwest boosted the demand for electric-powered air conditioning. Utilities met much of this peak in demand by burning natural gas.

Estimates of natural gas prices in 1998 are available through October for electric utilities and through November for the other sectors.[47] Cumulatively, average prices, unadjusted for inflation, are lower than in 1997 for all sectors. Residential and commercial users paid an estimated $6.91 and $5.50 per thousand cubic feet (Mcf), respectively, during the period, 1 and 5 percent below that of 1997. The average prices paid by the industrial and electric utility sectors were $3.10 and $2.38 per Mcf, respectively, 12 and 13 percent lower than in 1997.

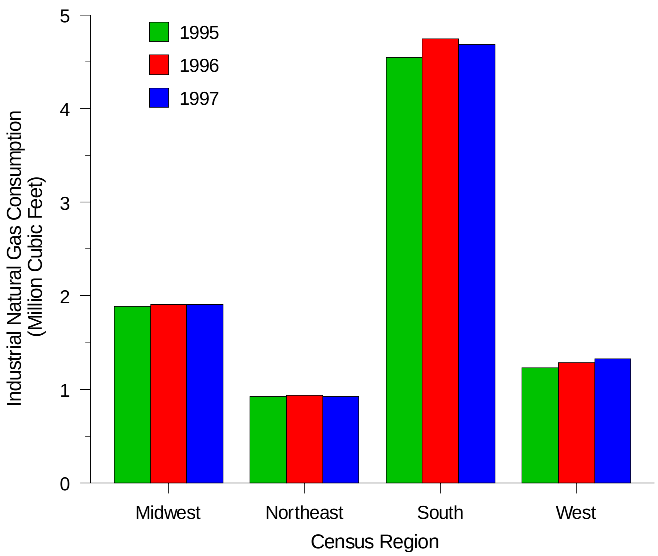
- **The average residential price of natural gas rose $0.49 per Mcf in 1997, reflecting the sharp rise in the average wellhead price in 1996** (Figure 14). (All prices are in 1998 dollars.)[48] Increases that occurred in the monthly average wellhead price late in 1996 were not fully passed on to residential consumers until 1997, in part because of the billing practices of many local distribution companies. These companies tend to base their charges to residential and commercial customers on long-term average costs in order to cushion the blow from sharp increases in wellhead prices. For example, between 1995 and 1996, the average residential price rose by only $0.17 per Mcf, even though the average wellhead price rose $0.61. Then in 1997, the average residential price rose $0.49 per Mcf to $7.01, while the average wellhead price rose only $0.11 to $2.34 per Mcf. Prices in the industrial and electric utility sectors are much more sensitive to changes in the wellhead price. The price paid by both sectors rose over $0.60 per Mcf in 1996, yet in 1997 the electric utility price was unchanged and the industrial price rose by only $0.11.

- **Residential expenditures for natural gas increased during the 1996-97 heating season even though consumption declined** (Figure 14). Residential expenditures were $23.5 billion (in 1998 dollars) during the 1996-97 heating season, 7 percent higher than in the prior heating season, even though consumption had declined by 6 percent. In contrast, both residential expenditures and consumption declined in the 1997-98 heating season. A combination of factors contributed to the higher expenditures during the 1996-97 heating season.[49] Unusually cold weather in November 1996 caused many natural gas providers to acquire higher-priced gas for their customers rather than withdraw supplies from storage, out of fear that storage supplies would not last through the winter. The prior heating season had been colder than normal, and the amount of natural gas in storage at the beginning of the 1996-97 heating season was lower than the previous season. The weather returned to normal, and for some months warmer than normal, later in the 1996-97 heating season, resulting in a net decline in natural gas consumption for the season. The strong demand in November 1996, however, had put pressure on wellhead prices, which rose from $1.94 per Mcf in October 1996 to $3.40 in January 1997. Although the impacts of this increase were somewhat delayed in the residential sector, they were felt before the heating season ended in March 1997.

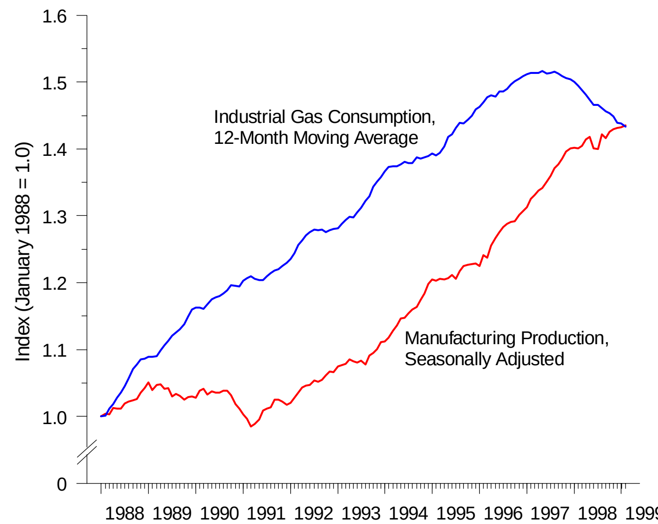
- **Gas continues to be the fuel of choice for heating most new single-family houses** (Figure 14).[50] Approximately two-thirds of the new single-family houses built from 1992 through 1997 were heated by gas, while nearly 30 percent were heated by electricity. The Midwest Census Region has the largest percentage of new single-family houses heated by gas, 91 percent, but only 21 percent of the 1.1 million new single-family houses constructed in 1997 were in the Midwest. The largest share of new home construction, 45 percent, was in the South where 52 percent of new houses were heated by gas.

## Figure 15. Industrial Natural Gas Consumption Was 8.5 Trillion Cubic Feet in 1998, 4 Percent Below the 1996 Peak

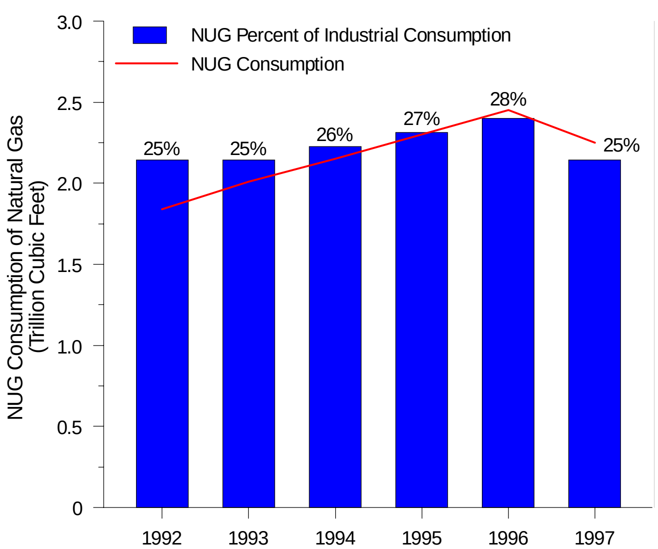
### *The South dominates industrial consumption*



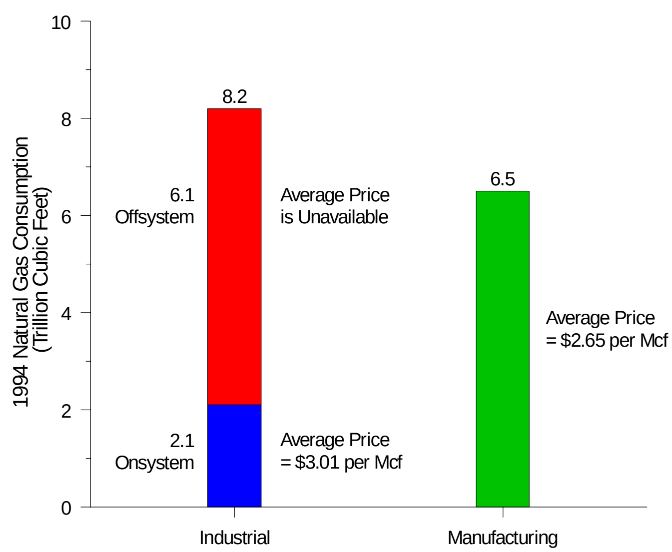

### *Industrial gas consumption is driven by manufacturing activity*




### *NUGs account for a significant share of industrial consumption*




### *Manufacturers paid less than the onsystem industrial price for natural gas in 1994*




NUG = Nonutility generator.

Source: Energy Information Administration (EIA), Office of Oil and Gas. **Industrial Consumption:** EIA, *Natural Gas Annual 1997*. **Index of Manufacturing Production:** derived from: Board of Governors of the Federal Reserve System. **Index of Industrial Consumption:** derived from EIA: 1988-1992—*Historical Monthly Energy Review 1973-1992*, 1993-1999—*Natural Gas Monthly*, various issues. **NUG Consumption:** EIA: 1992—*Annual Energy Review 1997*, 1993-1997—*Electric Power Annual 1997*, Vol. II. **NUG Percent:** derived from EIA: NUG consumption and industrial natural gas consumption—*Natural Gas Annual 1997*. **Manufacturing Data:** EIA, *Manufacturing Consumption of Energy 1994*.

# Industrial Gas Consumption

The industrial sector consumes more natural gas than any other sector, accounting for an estimated 44 percent of end-use consumption in 1998. Industrial consumption reached an historical peak of 8.9 trillion cubic feet (Tcf) in 1996 and has declined somewhat since then.[51] Consumption in 1998 is estimated to have been 8.5 Tcf, a 4-percent decline from the 1997 level of 8.8 Tcf. Monthly industrial consumption during 1998 ranged from 3 to 7 percent lower than in 1997 in all months except July, when levels were virtually the same. The South Census Region has long dominated industrial gas consumption, accounting for over half the total in 1997 (Figure 15). Industrial consumption in both the South and Northeast declined by 1 percent from 1996 to 1997, was unchanged in the Midwest, and increased by 4 percent in the West.

Industrial users paid an estimated $3.10 per thousand cubic feet for natural gas on average for January through November 1998.[52] This is 12 percent lower than the average of $3.54 paid during the same period in 1997. Industrial prices were lower in 1998 than in 1997 during most months of the year, with the most significant declines occurring at the beginning and end of the year. For example, the industrial price in January 1998 was 21 percent below that of January 1997 and the November 1998 price was 31 percent below that of 1997.

- **Industrial consumption of natural gas generally follows the trend in manufacturing activity** (Figure 15). From March 1991 (the bottom of the last recession)[53] through March 1997, the seasonally adjusted indices of industrial consumption and manufacturing production increased annually by 3.8 and 5.1 percent, respectively.[54] Since then, generally lower crude oil prices, fluctuating natural gas prices, and periods of warmer-than-normal weather have contributed to a leveling off and lowering of industrial natural gas consumption, yet the strong economy has continued to boost manufacturing output. From March 1997 to March 1998, the industrial gas consumption index declined by 1.5 percent while the manufacturing index rose by 5.6 percent.

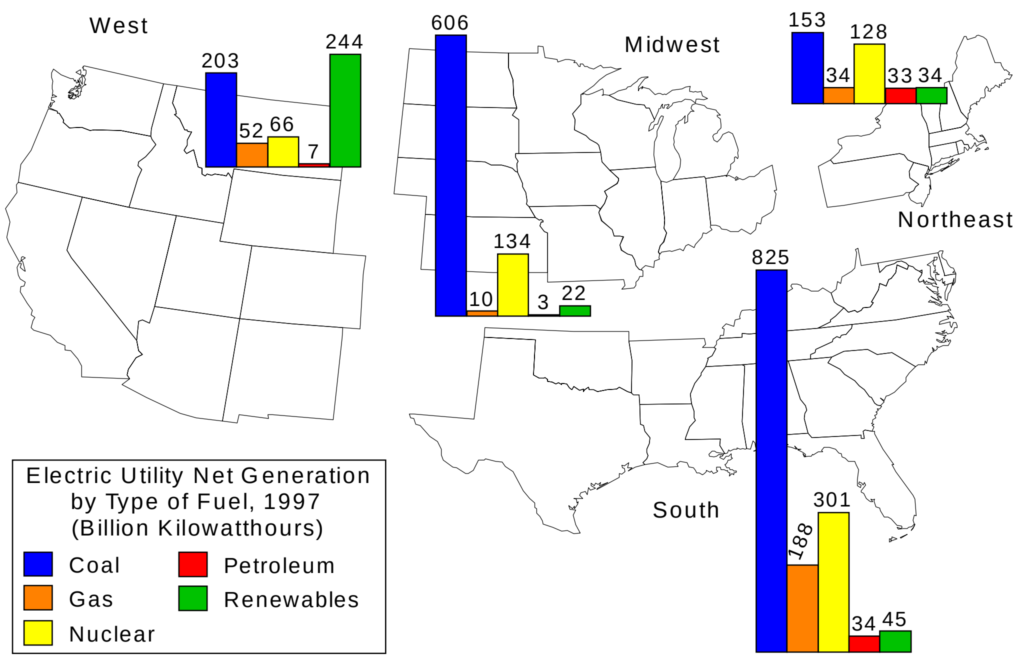
- **Nonutility generator consumption of natural gas accounts for a significant share of total industrial consumption—25 percent in 1997** (Figure 15).[55] Nonutility generators (NUGs) consist mainly of cogenerators, but also include independent and small power producers. Cogenerators use one source of energy to produce both electric power and another useful form of energy, such as heat or steam. Cogeneration can take several different forms. For example, natural gas may be used to generate electricity directly, with the waste heat used for another purpose, or the natural gas may be used in a boiler to generate steam, which in turn is used in manufacturing processes and to generate electricity. Nonutilities consumed an estimated 2.2 Tcf of natural gas in 1997. Natural gas consumption by nonutilities grew at an average rate of 4 percent annually from 1992 through 1997, while total industrial consumption grew 3 percent annually. However, nonutility consumption had grown at a 7-percent annual rate from 1992 through 1996 before falling by 8 percent in 1997. Nonutilities generate more electricity using natural gas than any other fuel. In 1997, natural-gas-fired nonutility gross generation was 206 billion kilowatthours, 54 percent of total nonutility generation. Coal was second, responsible for 15 percent of nonutility gross generation.

- **Manufacturing data provide insight into the average price paid for natural gas in the industrial sector.** As the interstate natural gas transportation system was restructured during the 1980s, large consumers, such as industrial firms, were among the first to seek alternatives to their traditional providers of natural gas. The Energy Information Administration (EIA) collects pricing information from the companies that actually deliver natural gas to the end user, typically a pipeline company or a local distribution company. The purchasing of natural gas from alternative providers, such as marketers, has been so strong in the industrial sector that by 1997 price data were available to EIA for only 18 percent of natural gas deliveries to industrial users.[56] EIA's quadrennial survey of manufacturers, last conducted in 1994, provides additional information on the average price that this portion of the industrial sector pays for natural gas.[57] In 1994, EIA's average industrial price was $3.01 per thousand cubic feet (Mcf), but this applied to only 26 percent of natural gas deliveries to industrial firms (Figure 15). In 1994, manufacturers paid an average of $2.65 per Mcf for natural gas. Total manufacturing purchases were 6.5 Tcf, or 79 percent of total industrial consumption in 1994.[58]

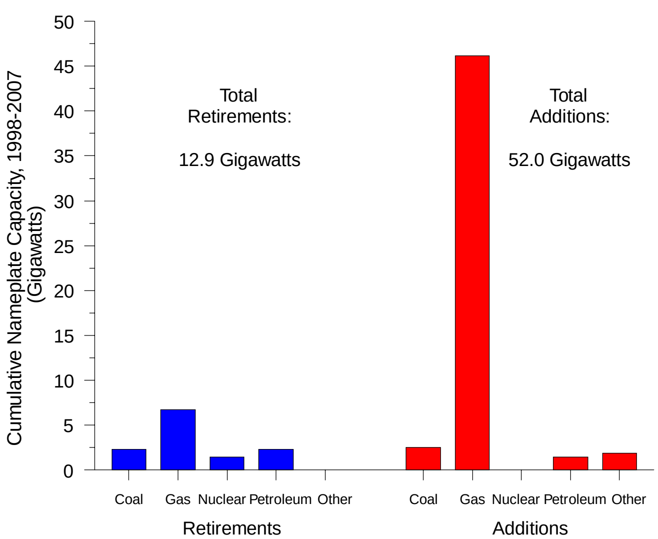
- **Electricity generation may be a growth area for natural gas in the industrial sector as distributed power becomes more economic.**[59] The use of natural gas to generate electricity may increase among manufacturers that are able to take advantage of distributed power technologies, many of which may be fueled by natural gas.[60] Distributed power consists of small generation units located closer to the user than the typical electric utility. Such units usually have a capacity of 30 kilowatts to 50 megawatts, compared with 500 to 1,000 megawatts for a central power plant (see p. 33).

## Figure 16. The Use of Natural Gas To Generate Electricity Is Expected To Grow

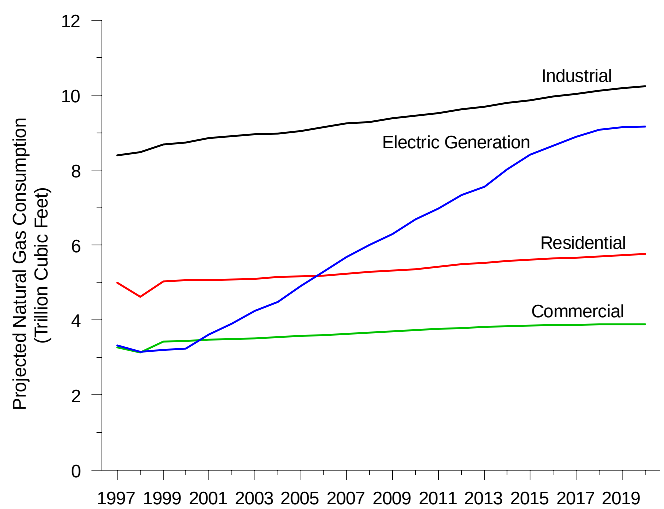
***Most electricity is generated by coal . . .***




***. . . But most capacity additions will be fueled by gas . . .***




***. . . Resulting in strong growth in natural gas for electricity generation***




Notes: "Gas" in Net Generation and Capacity Retirements and Additions is natural gas; refinery, blast-furnace, and coke-oven gases; and propane. Renewables consist mostly of hydroelectric power. Other consists mostly of waste heat and includes renewables. The regions are the U.S. Census regions and the West includes Alaska and Hawaii.

Sources: Energy Information Administration (EIA). **Net Generation:** *Electric Power Annual 1997*, Vol. 1. **Capacity Retirements and Additions:** *Inventory of Power Plants in the United States As of January 1, 1998*. **Projected Natural Gas Consumption:** *Annual Energy Outlook 1999*, National Energy Modeling System run AEO99B.D100198A.

# Electricity Generation

The electric utility sector is the only end-use sector that showed strong growth in natural gas consumption in 1998. Estimates for the first 11 months of 1998 show that electric utility consumption of natural gas was 11 percent above that of 1997 for the same period. The average price paid for natural gas (available through October 1998) was $2.38 per thousand cubic feet, 13 percent below that of 1997. Annually, natural gas consumption by electric utilities during the 1990s has been in the range of 2.7 to 3.2 trillion cubic feet (Tcf). Consumption in 1997 was 3.0 Tcf, 9 percent above the 1996 level but short of the historical peak of 4.0 Tcf set in 1972.

Several nuclear plant outages in 1997 helped boost net electricity generation by all types of fossil fuels. Total net generation set a record in 1997 at 3,123 billion kilowatthours (kWh), 45 billion kWh higher than in 1996. Electric power from nuclear plants declined by 46 billion kWh (7 percent) in 1997, but generation from coal increased by 50 billion kWh (3 percent) and from gas[61] by 21 billion kWh (9 percent).[62]

- **Although coal is used for most electricity generation, nearly all anticipated capacity additions will be fueled by gas** (Figure 16).[63] Sixty-three percent of the gas-fired additions are planned for the South Census Region, which generates more electricity than any other region. The South Census Region also generates the most electricity using gas. The 188 billion kWh generated by gas in the region in 1997 accounted for 13 percent of the region's total generation.

  From 1998 through 2007, 52 gigawatts of generating capacity is planned to be built in the United States, 89 percent of which will be gas-fired (Figure 16). Gas-fired units also dominate planned retirements during the period, accounting for 53 percent, but the total retirement capacity is only 13 gigawatts. Gas-fired capacity additions of 46 gigawatts planned for the period will more than offset the 7 gigawatts of gas retirements. The increase in gas-fired capacity will have environmental benefits because natural gas has much lower emissions of many pollutants than do coal or oil per Btu of fuel consumed (see Chapter 2, Table 2). For example, consumption of natural gas generates less than half the carbon dioxide of coal and approximately one-third less than that of oil.

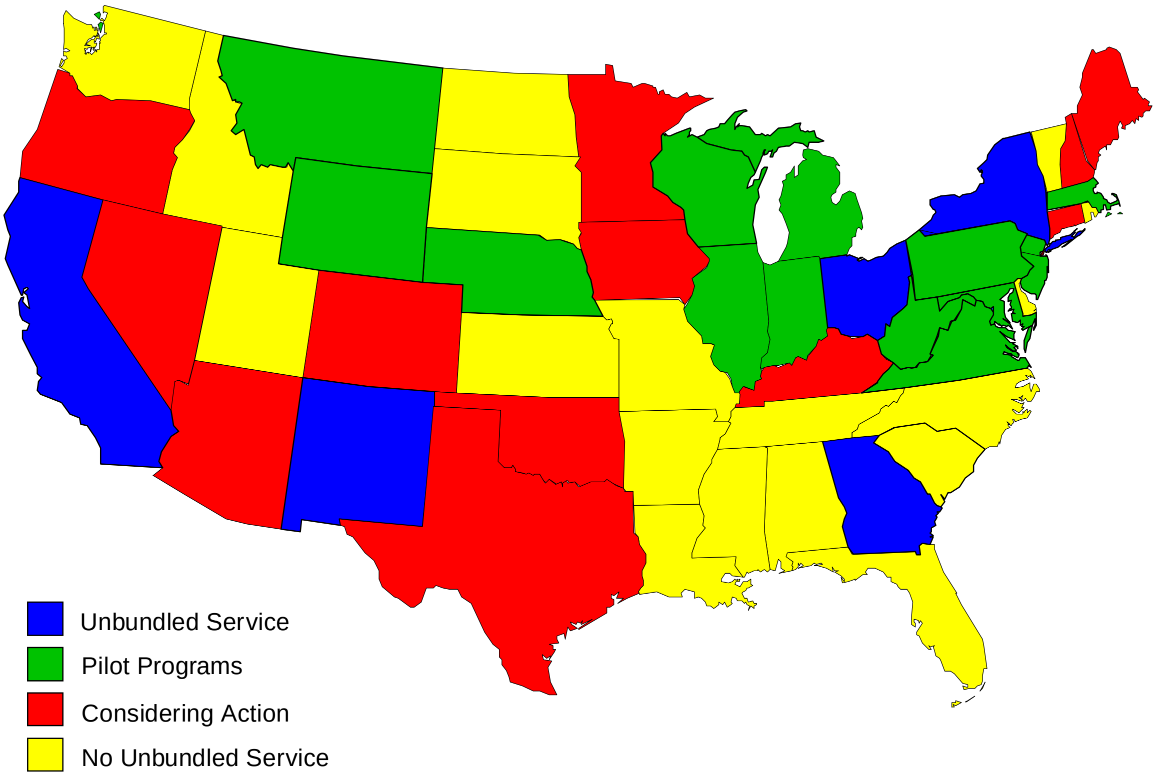
- **Natural gas used to generate electricity is projected to reach 9.2 Tcf in 2020, almost three times the 1997 level** (Figure 16).[64] The use of natural gas to generate electricity is expected to grow 4.5 percent annually from 1997 through 2020. This growth is spurred by the increased utilization of gas-fired plants and the addition of new turbines and combined-cycle facilities that are less capital-intensive than building new coal, nuclear, or renewable plants. The restructuring of the electric utility industry is also expected to open up new opportunities for gas-fired generation.[65] The South Census Region is expected to see the most growth in natural gas use by electric generators, accounting for 38 percent of the increase projected from 1997 through 2020.[66]

- **New "merchant" power plants, many of which are gas-fired, are coming on line.** The restructuring of the electric power industry[67] allows the construction of generation facilities without first acquiring long-term commitments for sale of the power generated. Several plants are being constructed in Texas where the State public utility commission is discouraging traditional electric utilities from building new generation facilities. An 85-megawatt plant, the first exempt wholesale generator in Texas, has been operating since 1997; a 240-megawatt plant came on line in the summer of 1998, in time to serve the unusually high demand for air conditioning; and a 500-megawatt plant is expected to come on line in 1999. These plants are among the first merchant plants in the United States. Florida's first merchant plant, a 500-megawatt gas-fired facility, is being planned by Duke Energy Power Services and is expected to come on line in late 2001. When providing peak generation, a 500-megawatt facility could use as much as 100 million cubic feet of gas per day.[68]

- **Distributed power generation may provide a new niche for natural gas, but there are different views on the role electric utilities should play.** Distributed power generation utilizes small (50 megawatts or less) generating units situated near the end user. Many of the new units may use natural gas, while others will use petroleum products or renewables.[69] Increased use of distributed power generation would help mitigate the need for utilities to increase their own generation capacity. However, while advocates agree that an open market with the ability to send clear price signals is crucial to the acceptance and development of distributed power generation, the ownership of the distributed units is a controversial issue that needs to be addressed. Some view ownership of these units by electric utilities as speeding the acceptance of distributed power generation. Others oppose utility ownership, fearing that such relationships could retard competition. Not all endorse the concept of distributed power generation. Critics, including some utilities, oppose the concept, arguing that the lack of clear standards could degrade system integrity.[70]

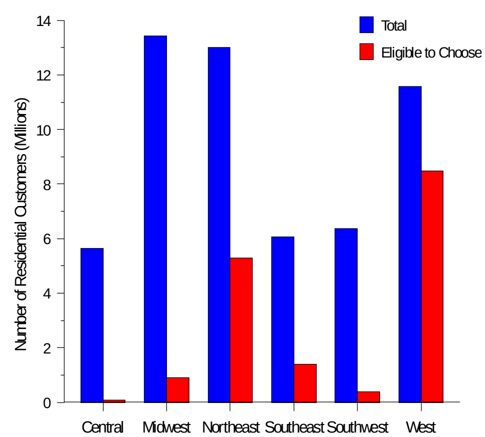
# Figure 17. Eighteen States and the District of Columbia Have Some Form of Residential Choice Program

*Five States have unbundled service*




*There is wide regional variability in residential customers' access to and participation in choice programs*

| Region | Number of Residential Natural Gas Customers (thousands) | | | Annual Residential Natural Gas Purchases (billion cubic feet) | | | Estimated Unbundled Purchases in 1998 as a Percent of 1997 Total |
|---|---|---|---|---|---|---|---|
| | 1997 Total | Eligible to Purchase Offsystem Gas | Participating in Retail Restructuring Programs | 1997 Total | Eligible to Purchase Offsystem Gas | Estimated 1998 Unbundled Purchases | |
| Central | 5,647 | 92 | 63 | 558 | 10 | 6.7 | 1.2 |
| Midwest | 13,428 | 905 | 139 | 1,665 | 108 | 16.7 | 1.0 |
| Northeast | 13,004 | 5,280 | 307 | 1,249 | 498 | 31.1 | 2.5 |
| Southeast | 6,056 | 1,400 | 141 | 412 | 103 | 10.4 | 2.5 |
| Southwest | 6,366 | 380 | 0 | 439 | 31 | 0.0 | 0.0 |
| West | 11,571 | 8,494 | 44 | 645 | 449 | 2.3 | 0.4 |
| **Total** | **56,072** | **16,552** | **694** | **4,968** | **1,199** | **67.2** | **1.4** |




Note: Estimated Unbundled Purchases assumes each residential customer participating in a State's retail unbundling program purchased from a third-party service provider the same amount as the State's annual average consumption per residential customer.

Sources: Energy Information Administration (EIA), Office of Oil and Gas. **1997 Total Residential Gas Customers and Purchases:** derived from *Natural Gas Annual 1997* (October 1998). **Number of Eligible Residential Customers and Number Participating in Retail Restructuring Programs:** derived from General Accounting Office, *Energy Deregulation: Status of Natural Gas Customer Choice Programs* (December 1998) and information gathered by EIA analysts.

# Retail Unbundling

The continuation of industry restructuring at the State level has important implications for residential and small commercial natural gas consumers. Retail unbundling, or restructuring, is division of the services required to provide gas to the end user into various components, and the ability of the customer to purchase those components separately. Large commercial and industrial consumers have had the option to purchase natural gas from offsystem providers for years,[71] whereas a "choice" for residential and small commercial customers (traditionally known as "core" customers) has only recently been available.[72] State regulators and lawmakers, who are responsible for designing and implementing retail restructuring programs, have delayed implementing customer choice until they could ensure reliable service and protect the interests of captive residential and commercial customers. As of July 31, 1998, 5 of the Lower 48 States have implemented complete unbundling programs for core customers, 13 States plus the District of Columbia have customer choice pilot programs, 12 States are considering action, and 18 have no plans to implement even pilot programs (Figure 17).[73]

- **About 65 percent of U.S. residential gas consumers live in States that have either completely unbundled retail service or have active pilot programs in place.** The degree to which these core customers are eligible and participating in choice programs varies. Currently, 78 percent (14.3 million) of the residential customers living in the five States with complete retail unbundling are eligible to choose their natural gas provider.[74] However, only 2 percent (301,721) of the eligible customers are participating. There is a larger participation rate for the 2.3 million residential customers who are eligible for the pilot programs underway in 14 States, with over 17 percent (392,448) participating. These 2.3 million customers represent 13 percent of the residential customers in those 14 States.

- **Unbundled residential gas purchases could have reached an annualized level of 67 billion cubic feet (Bcf) in 1998, or 1.4 percent of the 5.0 trillion cubic feet (Tcf) of gas consumed by residential customers in 1997, based on current customer choice participation levels.**[75] However, the amount of unbundled gas purchases varies significantly by region (Figure 17). The largest estimated offsystem purchases exist in the Northeast where 31 Bcf is associated with customers participating in choice programs. While end-use services in New Mexico are completely unbundled, customers are not participating in a choice program because third-party service providers have not offered service in the State.[76]

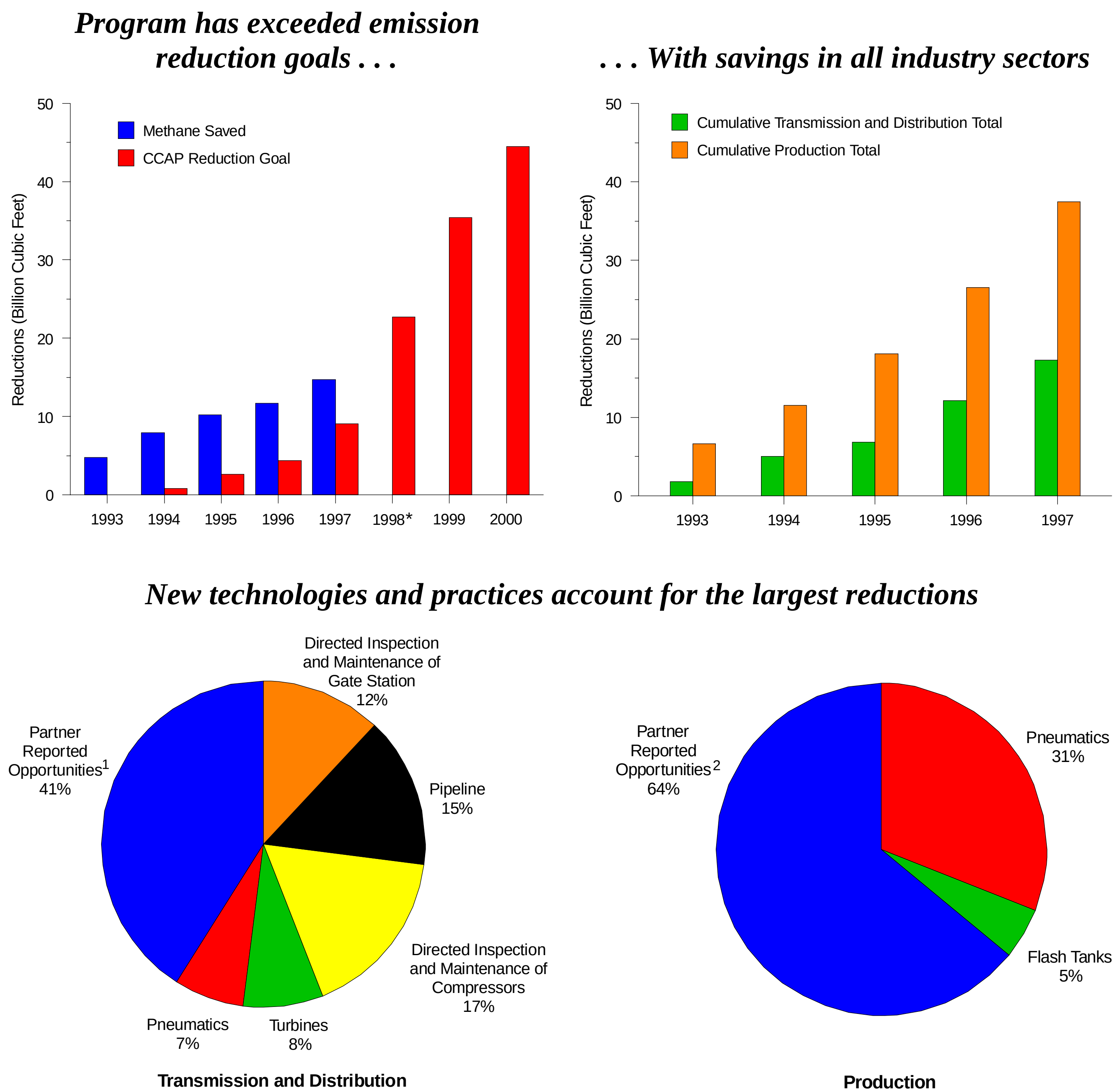
- **Residential customers have not fully embraced retail unbundling programs when given the opportunity**. Customers and State regulators have raised questions about the benefits of retail unbundling. There does not appear to be systematic monitoring or measurement of the overall impact of retail restructuring. In addition, the ability to measure price and customer savings may degrade as more LDC customers purchase offsystem gas.[77] Some rural communities are particularly concerned that they will face radically increased costs and fewer purchasing options as a result of restructuring. In response, marketers have offered incentives to attract retail customers, such as a guaranteed fixed percentage or dollar savings as compared with the LDC's gas cost.[78]

- **Some marketers have withdrawn from participation in retail restructuring programs as a result of the lack of customer participation.**[79] Marketers fear that the staffing and administrative costs of providing retail service may not be recovered without enough customer participation. Marketers are also concerned that direct assignments of LDC transportation capacity will erode the profitability of providing retail services. One way marketers have been able to lower costs is to use more interruptible service in their transportation portfolio. If they are required to accept responsibility for the LDC's firm transportation contracts, the marketers' profit margins may suffer.[80] Conversely, if the LDCs are required to retain unneeded firm transportation capacity, the stranded costs may have to be recovered from LDC shareholders, the pipeline company, or other customers within the LDC's service area.

- **Service reliability and supplier performance are two issues of general concern to State regulators as they determine how to capture the benefits of unbundled service for core customers.** Questions relate to supplier qualifications, access to information, allocation of upstream pipeline capacity, and the LDC's obligation to serve core customers if a "third party" service provider fails to deliver gas. A number of States are examining these and other retail restructuring issues.

- **In an effort to protect consumers, some States[81] require marketers to agree to certain business practices and standards in order to operate in the State**. Currently these standards vary by State, although there has been a proposal to establish national standards of conduct for marketers.[82] Under the proposal, the marketer[83] would be able to use a seal of approval, "Certified Energy Marketer," if it agrees to abide by these "fair marketing" practices.

## Figure 18. Natural Gas Industry Partners with EPA To Reduce Methane Emissions to the Atmosphere




EPA = Environmental Protection Agency. CCAP = Climate Change Action Plan.

*The 1998 goal was recently increased from 18.9 to 22.7 billion cubic feet.

[1]The partner reported opportunities in the transmission and distribution sectors include: replacing engine gas starters with air starters, lowering pipeline pressure prior to maintenance, installing 3-phase separators on dehydrator reboilers, and other operational practices.

[2]The partner reported opportunities in the production sector include: utilizing down-hole plunger lifts in wells, using lower heater treater temperature, inspecting and replacing tank vent seals, eliminating and consolidating excess dehydrators, and numerous other operational practices.

Source: Environmental Protection Agency, *1997 Natural Gas STAR Annual Report.*

# New Technology and the Environment

Several new natural gas technologies and initiatives could lead to environmental improvement. The natural gas industry in partnership with the Environmental Protection Agency (EPA) established the "Natural Gas STAR program" in 1993 to reduce methane emissions to the atmosphere. In the program, companies agree to implement technologies and management practices designed to minimize or prevent gas loss and to improve system efficiency. Reducing methane emissions can have an impact on slowing the rate of climate change and can also save money for the industry. In another program, research and testing efforts are underway to use liquefied natural gas (LNG) in place of diesel fuel, which could significantly reduce nitrogen oxide, carbon dioxide, and hydrocarbon emissions in comparison with those of current diesel fuel. In addition, gas-to-liquids technology may be coming of age, with much activity in the research end of the industry, potentially reducing methane flaring.

- **Partners in the Natural Gas STAR program exceeded their emission reduction goal for 1997 (9.1 billion cubic feet (Bcf)) by 75 percent, or 6.8 Bcf.** STAR partners have prevented the release of about 54.8 Bcf of methane through the program from 1993 to 1997 (Figure 18). This success prompted the 1998 goal to be changed from 18.4 to 22.7 Bcf. EPA has worked with several States and program partners to adjust regulations so as to facilitate use of "best management practices" (BMPs) that reduce methane emissions. Other technologies and management practices initiated since the STAR program was implemented ("partner reported opportunities") have resulted in 41 percent of the methane reductions in transmission and distribution operations and 64 percent of those in production-related activities.

- **The Natural Gas STAR program has two BMPs to reduce methane emissions from natural gas dehydration facilities, which emit about 22 Bcf of methane per year into the atmosphere.** These dehydrators were ranked as the fourth greatest source of toxic emissions of hazardous air pollutants in 1993 (the latest year available). EPA has a proposed rulemaking regarding reduction of hazardous air pollutants from oil and gas operations that specifically addresses dehydrators. The BMPs include the installation of flash tank separators and a reduction of the triethylene glycol (TEG) circulation rates. As TEG absorbs water from natural gas, it also absorbs the methane that is vented to the atmosphere when the glycol is regenerated. Economic analyses demonstrate that dehydration units circulating between 150 and 450 gallons of TEG per hour can achieve payback of costs in 6 months to 2.5 years of the installation of a flash tank separator. Depending on the size of the unit and the percent of overcirculation, a reduction in TEG circulation rates can save between 130 and 13,140 thousand cubic feet of methane per year.

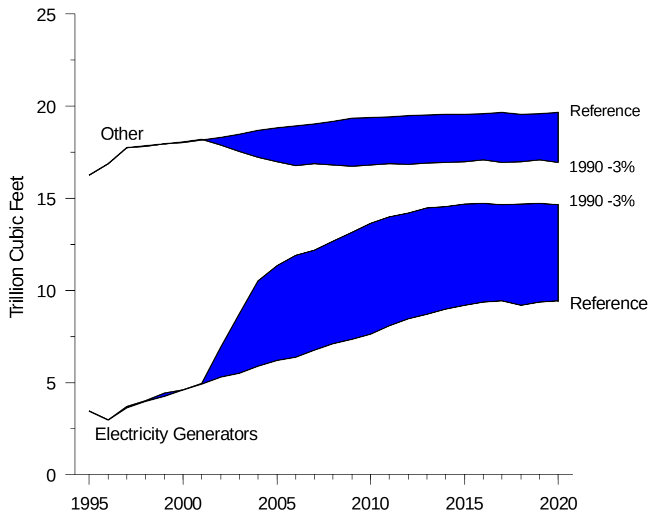
- **LNG has been tried in a locomotive engine.** Engineers at the Southwest Research Institute working for GasRail USA, a cooperative industry research project of industry, Federal, and State participants, have achieved a 75-percent reduction in nitrogen oxide emissions on a 4,200-horsepower, 16-cylinder, natural-gas-fueled engine for use in passenger engines.[84] The selected system used small amounts of diesel fuel as an ignition source for the high-pressure natural gas that is injected late into the combustion cycle. The engine also reduced carbon dioxide emissions by 25 percent. EPA has called for railroad locomotives to meet a 25-percent reduction in nitrogen oxides and a 40-percent reduction in hydrocarbons and particulate matter by 2000.

- **Gas-to-liquids technology has taken significant steps towards commercial operation in specific producing areas in the United States.** Gas-to-liquids (GTL) projects have been announced in several locations around the world, with BP and Exxon considering it for Alaskan North Slope gas. In October 1997, ARCO announced a joint project with Syntroleum Corporation to build a pilot plant of about 70 barrels per day at an ARCO refinery near Bellingham, Washington.[85] The Syntroleum Corporation effort is to develop GTL systems that are economic at the level of 50,000 to 2,000 barrels per day.[86] The Department of Energy has selected Air Products and Chemicals, Inc. to develop a ceramic membrane, which could reduce greatly the cost of converting natural gas to transportation-grade liquid fuels and premium chemicals.[87] Praxair Inc., Amoco Corp., BP, Sasol, and Statoil have a technical alliance to study ceramic membranes for GTL.[88] Several other companies have shown an interest in GTL plants.[89]

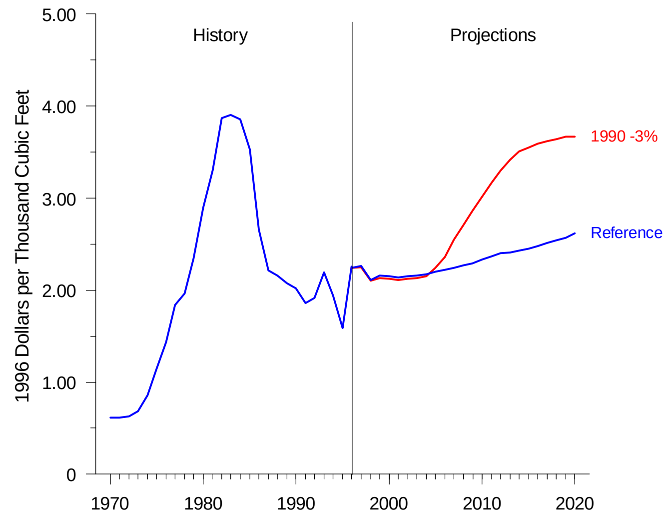
- **New developments in fuel cell technology could lead to substantially lower carbon dioxide emission levels.** Liquid methanol as a hydrogen carrier to power a fuel cell was developed for the military by the National Aeronautics and Space Administration's (NASA) Jet Propulsion Laboratory and the University of Southern California. This direct methanol fuel cell runs relatively cool, is highly efficient, and can be supported by existing gasoline fueling infrastructure. A full fuel-cycle analysis[90] shows that the carbon dioxide emissions released by a methanol fuel cell will be less than half that of today's gasoline internal combustion engines.

## Figure 19. Kyoto Implementation Could Have Far-Reaching Impacts on Gas Use and Prices

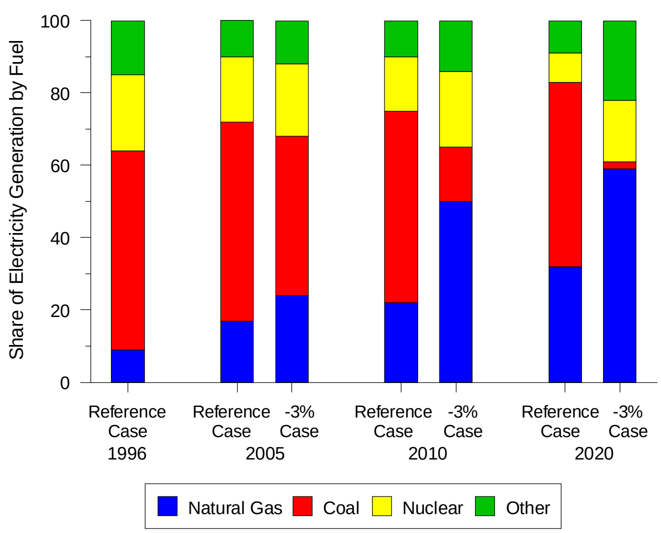
*Gas use for electricity generation climbs above the reference case, but other uses fall below*



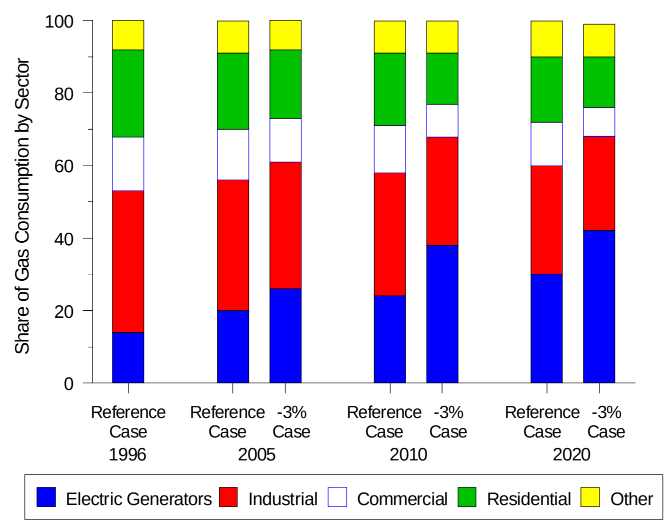

*Wellhead prices are projected to move up, perhaps sharply, but to remain below peak of 1980s*




*Gas share of generation offsets declines in coal*




*Electric generation could command largest share of gas consumption by 2010*




Note: The Energy Information Administration report *Impacts of the Kyoto Protocol on U.S. Energy Markets and Economic Activity* examines a series of six cases looking at alternative carbon emission levels. The Reference Case represents projections of energy markets and carbon emissions without any enforced reductions and is presented as a baseline for comparison of the energy market impacts in the reduction cases. The highest consumption patterns for natural gas are seen in some of the intermediate cases, principally the "Stabilization at 1990 Levels" and the "3 Percent Below 1990 Levels." For these figures, the Reference Case and the "3 Percent Below 1990 Levels" are used to illustrate the potential range of additional demand.

Source: Energy Information Administration, *Impacts of the Kyoto Protocol on U.S. Energy Markets and Economic Activity* (October 1998), AEO98 National Energy Modeling System runs KYBASE.D080398A and FD03BLW.D080398B.

# Kyoto Protocol

Overall natural gas consumption is projected to increase about 10.3 trillion cubic feet (Tcf) from 1997 to 2020,[91] mainly because of its increased use as a fuel for electricity generation. The expected use of natural gas for generation is even higher when the potential impact of the Kyoto Protocol is considered. This agreement, which has been signed but not ratified by the United States, sets carbon emission reduction targets relative to 1990 for the "Annex I" countries,[92] which include the United States, Canada, and other developed countries. For the United States, the target is 7 percent below 1990 carbon emission levels. In 1997, U.S. energy-related carbon emissions from fossil energy consumption were 1,480 million metric tons, about 10 percent above the 1990 level. Without new policies, these emissions are projected to increase at an annual rate of 1.3 percent through 2020, according to the *Annual Energy Outlook 1999* (*AEO*).

Electricity use is a major cause of carbon emissions. Although electricity produces no emissions at the point of use, its generation currently accounts for 36 percent of total carbon emissions. According to the *AEO*, that share is expected to increase to 38 percent in 2020. Coal, which accounts for about 52 percent of electricity generation in 2020 (excluding cogeneration), is projected to produce 81 percent of electricity-related carbon emissions. In 2020, natural gas is expected to account for 30 percent of electricity generation but only 18 percent of electricity-related carbon emissions.

Findings in a recent Energy Information Administration (EIA) Service Report, *Impacts of the Kyoto Protocol on U.S. Energy Markets and Economic Activity* (*Kyoto*), highlight the significant role that natural gas may play in any approach to reduce carbon emissions.[93] The report was undertaken at the request of Congress using the same methodologies and assumptions in the *AEO 1998*, with no changes in assumptions about policy, regulatory actions, or funding for energy and environmental programs. In 1990, U.S. energy-related carbon emissions were 1,346 million metric tons. The Kyoto target is 1,250 million metric tons, on average, in the commitment period 2008 to 2012. While the details of the final implementation are not fully decided, countries have some flexibility in how they can meet these targets. Joint implementation projects are permitted among the Annex I countries, allowing a Nation to take emissions credits for projects in other countries that reduce emissions or enhance emission-absorbing sinks, such as forests and other vegetation. Meeting the target entirely by domestic reduction is the most constrained option for the United States. Some results of the *Kyoto* study include:

- **If the emission reduction target of the Kyoto Protocol were imposed, the U.S. coal and oil industries would see lower consumption and production whereas the natural gas industry would expand.** Compared with the reference case (which does not incorporate the Protocol), natural gas consumption would be 0.6 to 3.5 Tcf higher in 2010 and 1.8 to 3.3 Tcf higher in 2020 under a number of alternative scenarios. Natural gas wins out over coal and oil in the carbon reduction cases, because its carbon content per Btu is only 55 percent of that for coal and 70 percent of that for oil.

- **When carbon emission limits are first imposed in 2005, rapid growth in natural gas electricity generation is projected in scenarios with rapid increases in carbon prices.**[94] The scenario presented in Figure 19 (1990 -3%) results in one of the higher gas consumption projections in the *Kyoto* study. In this case, gas-fired generation ramps up quickly in 2005, because the rising carbon price makes existing natural gas plants more economical than existing coal plants and because new natural gas plants can be quickly brought on line. In this case, after the initial shift to natural gas, the growth in natural gas generation continues, but at a slower rate. In the later years of the forecast period, natural gas generation does not increase as rapidly, because carbon-free renewable technologies become economical as the demand for electricity grows and natural gas prices increase. Under this scenario, natural gas could hold as much as a 60-percent share of electric generation in 2020, compared with one-third of the generation in the reference case, which excludes the Protocol (Figure 19).

- **Higher natural gas prices lead to conservation and the penetration of more efficient technologies**. Natural gas prices are higher in the carbon reduction cases than in the reference case, both at the wellhead (Figure 19) and at the burner tip. At the wellhead, higher production to satisfy increased natural gas consumption, in the face of increasingly expensive resources, boosts prices. At the burner tip, some consumers may see more than double the prices they could have expected without the carbon reduction polices. This results in lower consumption levels for the nongeneration sectors of the economy.

- **Pressure to merge gas and electricity companies could mount as the advantages of arbitraging the two markets become apparent.** Powerplant use of natural gas (excluding industrial cogeneration) in the carbon reduction cases is projected to rise from roughly 3 Tcf in 1996 to between 8 and 12 Tcf in 2010 and between 12 and 15 Tcf in 2020. By 2010, the electric generators could become the largest consumers of natural gas (Figure 19).

# Chapter 1 Endnotes

1. Energy Information Administration, *Annual Energy Outlook 1999*, DOE/EIA-0383(99) (Washington, DC, December 1998).

2. Energy Information Administration, *Impacts of the Kyoto Protocol on U.S. Energy Markets and Economic Activity*, SR/OIAF/98-03 (Washington, DC, October 1998).

3. Average wellhead prices were converted to a Btu-basis using 1,026 Btu per cubic foot, which is the estimated heat content for dry gas production as reported in: Energy Information Administration, *Monthly Energy Review*, DOE/EIA-0035(98/12 (Washington, DC, December 1998), Table A4, "Approximate Heat Content of Natural Gas."

4. The December 1998 wellhead price of $1.69 per million Btu was not available in the February edition of the Energy Information Administration's *Natural Gas Monthly*, DOE/EIA-0130(99/02), but it appears in subsequent issues.

5. Correlation coefficients were 0.77 or more. A correlation coefficient measures the degree of linear association between two random variables, and its values range from –1 to +1. Four trading centers were chosen because they are located in geographically separated markets. They are Henry Hub, LA; Waha, TX; Opal, WY; and Blanco, NM.

6. There are currently two other natural gas futures contracts traded on NYMEX. One is the NYMEX Division Permian Basin contract, designed to reflect more closely conditions in the Western United States. This contract was initiated on May 31, 1996. Physical delivery on this contract occurs at El Paso Natural Gas Company's Permian Pool facility in West Texas. The other is the so-called Alberta contract, based on delivery in Alberta, Canada (Nova Gas Transmission Ltd. pipeline system or specified interconnect points). That contract began trading on September 27, 1996.

7. Traders must disclose all futures positions consisting of 100 or more contracts. The standardized delivery volume for a contract is 10,000 million Btu. Marketers fall into the category of "Commercial Trader," or industry participants that actually trade in the physical commodity. Other entities that are classified as commercial traders include producers, pipeline companies, gas processors, local distribution companies, and end users. The category "Noncommercial Trader" consists of entities that have no interest in actual receipt of the physical commodity but are either trading on a very short-term basis in order to facilitate trades of others (market makers) or are attempting to profit from futures contract price fluctuations (speculators). Noncommercial traders consist of financial companies, mutual and hedge funds, floor traders, and individual investors.

8. The historical peak in dry natural gas production was 21.7 trillion cubic feet in 1973.

9. Natural gas production from different resources in 1997 was estimated by the Energy Information Administration's (EIA), Office of Oil and Gas. The estimated proportion of production from each resource was derived from data input to EIA's National Energy Modeling System (NEMS) for the *Annual Energy Outlook 1999*, DOE/EIA-0383(99) (Washington, DC, November 1998), NEMS run, AEO99B.D100198A. These proportions were applied to the total U.S. dry production for 1997 in EIA's *Natural Gas Annual*, DOE/EIA-0131(97) (Washington, DC, October 1998), Table 1.

10. A new water depth record was set on August 13, 1997, when Petroleo Brasileiro SA began producing crude oil from its South Marlin 3B off the coast of Brazil in 5,607 feet of water. See Pedro J. Barusco and others, "Water depth production record set off Brazil," *Oil & Gas Journal* (September 29, 1997), p. 59. For more information on offshore production issues, see Chapter 4, "Offshore Development and Production."

11. The production tax credit is available for gas produced from geopressurized brine, Devonian shale, coal seams, or tight formations. The gas must be produced from wells drilled after December 31, 1979, and by December 31, 1992. To receive the credit, the gas must be produced and sold before January 1, 2003.

12. Natural gas well completions are the sum of gas exploratory and developmental wells. Data are from the Well Completion Estimation Procedure (WELCOM) as of April 5, 1999, which is maintained by the Energy Information Administration's Office of Oil and Gas.

13. These regions conform to those used for the onshore Lower 48 States in the Oil and Gas Supply Model in the Energy Information Administration's National Energy Modeling System. They are defined as: (1) Northeast: CT, DC, DE, GA, IL, IN, KY, MA, MD, ME, MI, NC, NH, NJ, NY, OH, PA, RI, SC, TN, VA, VT, WI, and WV; (2) Gulf Coast: AL, FL, LA, MS, State and Federal waters of the Gulf of Mexico, and Eastern and Southern TX (Railroad Commission Districts 1-6); (3) Midcontinent: AR, IA, KS, MN, MO, NE, OK, and the TX Panhandle (Railroad Commission District 10); (4) Southwest: Eastern NM and West TX (Railroad Commission Districts 7B, 7C, 8, 8A, and 9); (5) Rocky Mountain: AZ, CO, ID, MT, ND, NV, SD, UT, WY, and Western New Mexico; (6) West Coast: CA, OR, and WA.

14. Energy Information Administration, Well Completion Estimation Procedure (WELCOM) as of April 5, 1999.

15. Energy Information Administration, *Monthly Energy Review*, DOE/EIA-0035(99/01) (Washington, DC, January 1999), Table 5.1.

16. *Proved reserves* of natural gas are the estimated quantities that analysis of geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions.

17. *Total discoveries* are the sum of extensions to the proved volume of old reservoirs in old fields, the proved volume of new reservoir discoveries in old fields, and the proved volume of new field discoveries.

18. *Ultimate recovery appreciation* (URA) refers to the commonly observed phenomenon that the estimated ultimately recoverable volume of oil or gas in most oil and gas fields tends to increase (appreciate) over post-field discovery time. This occurs for a wide variety of reasons.

19. The stated volume represents the sum of onshore and offshore Lower 48 States undiscovered resources in conventional reservoirs, continuous-type resources, and the expected proved ultimate recovery appreciation in known fields. Alaskan gas is neither now nor in the foreseeable future expected to be marketed in the Lower 48 States. Resource estimates are from: D.L. Gautier and others, U.S. Geological Survey Digital Data Series, *1995 National Assessment of United States Oil and Gas Resources — Results, Methodology, and Supporting Data*, [CR-ROM] DDS-30, Release 2 (1996); and Minerals Management Service, Resource Evaluation Program, *An Assessment of the Undiscovered Hydrocarbon Potential of the Nation's Outer Continental Shelf*, OCS Report MMS 96-0034 (Washington, DC, 1996).

20. *Nonassociated natural gas* is natural gas not in contact with significant quantities of crude oil in the reservoir. *Associated gas* is the volume of natural gas that occurs in crude oil reservoirs either as free gas (associated) or in solution with crude oil (dissolved). E.D. Attanasi, D.L. Gautier, and D.H. Root, *Economics and Undiscovered Conventional Oil and Gas Accumulations in the 1995 National Assessment of U.S. Oil and Gas Resources: Coterminous United States*, U.S. Geological Survey Open File Report 95-75H (Washington, DC); and E.D. Attanasi, *Economics and the 1995 Assessment of United States Oil and Gas Resources*, U.S. Geological Survey Circular 1145 (Washington DC, 1998).

21. These unit cost estimates are based on assumptions reflecting the technology and economic conditions existing as of the mid-1990s and an assumed 12 percent after-tax rate of return. U.S. Geological Survey Open File Report 95-75H (Washington, DC); and U.S. Geological Survey Circular 1145 (1998).

22. At least 551 trillion cubic feet of the remaining untapped natural gas resource base underlies federally owned lands.

23. A Hinshaw pipeline is exempt from regulation by the Federal Energy Regulatory Commission (FERC). Although it imports natural gas from Canada, Empire State Pipeline operates within New York State and is subject to regulation by the New York Public Service Commission. Nonetheless, FERC authorization was required for Empire to construct import facilities at the U.S./Canada border.

24. The conversion value used is 47,063 cubic feet per metric ton of LNG. Source: *Costs for LNG Imports into the United States*, prepared by Energy and Environmental Analysis, Inc. for the Gas Research Institute (August 1988), p. 7.

25. For more information on interstate pipeline expansion during the early 1990s, see Energy Information Administration, *Deliverability on the Interstate Natural Gas Pipeline System*, DOE/EIA-0618 (Washington, DC, May 1998).

26. The potential capacity levels for 1999 and 2000 in this section include adjustments and updates to data presented in Chapter 5, which covered project proposals and completions only through the first 8 months of 1998. In general, these adjustments reflect the postponement of 13 projects originally scheduled for completion in 1998 to 1999 or beyond. They also reflect the addition of several new projects announced in late 1998 and scheduled for completion in 1999 or 2000.

27. Temperatures during the winter of 1997-98 were warmer than normal for 43 of the Lower 48 States; 13 States experienced average winter temperatures that were more than 10 percent warmer than normal. For the 27 States east of the Mississippi River, which account for 60 percent of working gas inventories on average at the beginning of the heating season, there were 9.4 percent fewer heating degree days than normal for the 1997-98 winter.

28. A seasonal adjustment technique, developed by the Bureau of the Census (designated "Census X-11") and adapted to natural gas storage data, is used to remove annual variation from the data. The procedure calculates "seasonal factors" that determine the upper and lower bounds of the expected monthly inventory ranges.

29. National average utilization rates for the past two heating seasons are based on data reported to the Energy Information Administration on the EIA-191, "Monthly Underground Gas Storage Report" for 26 salt cavern facilities.

30. In 1998, at least three companies made application to the Federal Energy Regulatory Commission to abandon operations at eight storage fields. ANR Pipeline Co. plans to abandon five storage fields in Michigan, two of which it owns and three that it leases from its affiliate Mid Michigan Gas Storage Company. Columbia Gas Transmission Corporation has applied to abandon one field each in West Virginia (Derricks Creek) and Pennsylvania (Munderf–inactive since 1992). Williams Gas Pipelines Central plans to close the Craig storage field near Kansas City, KS. In most cases, the companies assert that the abandoned capacity will not be missed and that their respective systems will be more efficient and less expensive to operate without them. The eight abandoned fields comprise about 10.7 billion cubic feet of working gas capacity and 154 million cubic feet of daily deliverability.

31. One company—Columbia Gas Transmission Corporation—accounted for 14 of the 22 projects, comprising over 6 billion cubic feet of added working gas capacity and almost 120 million cubic feet per day of added deliverability.

32. According to annual capacity reports filed by respondents to the Energy Information Administration's monthly EIA-191 survey, "Monthly Underground Storage Report," 19 companies made capacity adjustments to a total of 98 existing storage facilities, effective for 1998. These adjustments amounted to a net decrease in working gas capacity of about 82 billion cubic feet and a net decrease in deliverability of about 94 million cubic feet per day.

33. Eleven of these are expansions to existing facilities. Of the eight proposed new facilities, five are LNG projects, two of which are new only in the sense that they will offer interstate storage services for the first time.

34. Does not include annual capacity adjustments filed by EIA-191 respondents.

35. Particularly notable is the lack of additional capacity from new storage facilities in the past 2 years, after having been the leading source for added capacity earlier in the decade.

36. Northeast Hub Partners' Tioga salt cavern project involves development in a salt formation that happens to lie directly beneath CNG's Tioga depleted reservoir storage field. CNG maintains that project development could seriously damage or even destroy its reservoir storage. The Federal Energy Regulatory Commission certificated the project in April 1998, contingent upon the two parties reaching a mutually agreeable arrangement requiring Northeast Hub Partners to indemnify CNG from any losses that might result from project construction. The fight therefore most recently centered on issues of asset valuation and types and amounts of insurance.

37. The unique thing about these projects is that they all propose to connect to interstate pipelines and to offer some if not all of their storage capacity to customers on an open-access basis. Until recently, most LNG facilities were "captive" assets of individual LDC's' distribution systems and were primarily held in reserve for peaking needs.

38. Horizontal wells can vastly increase the deliverability and cycling characteristics of certain reservoirs because the well bores expose a much greater surface area to the stored gas than traditional vertical wells that pass through or terminate in the pay zone. The Gas Research Institute has funded research in this technology and its application to gas storage operations for a number of years.

39. Companies that have experimented with the technology include ANR Pipeline Co., CNG Transmission, Colorado Interstate, Columbia Gas Transmission, and Tejas at facilities in CO, MI, OK, PA, and WV.

40. Annual information and comparisons are represented on a "heating year" basis or for the 12 consecutive months ending March 31. The total volume of released capacity held by replacement shippers during a season is the sum of the capacity effective on each day of the season. For example, if a 60-day contract for Z thousand cubic feet per day is effective within a season, then the sum of capacity held for the season would include Z thousand cubic feet 60 times for that contract. If that 60-day contract were only effective, for example, for the last 20 days of the season, then the sum for the season would include Z thousand cubic feet 20 times, and the sum for the next season would include Z thousand cubic feet 40 times for that contract.

41. It is assumed that each unit of pipeline capacity held by a replacement shipper was used fully (100 percent load factor) to deliver natural gas to market.

42. The percent-of-maximum rates were derived from a subset of capacity release transactions, representing 85 percent of all capacity release transactions, that contained reliable maximum rate information.

43. Capacity reservation rates are stated in units to identify the cost to reserve a specified amount of capacity on each day for an entire month. For example, $1.00 per Mcf-Mo. indicates that it would cost $1.00 to reserve 1 thousand cubic feet of capacity each day for a given month.

44. Based on heating degree days from the *Natural Gas Monthly*, DOE/EIA-0130(98/04) (Washington, DC, April 1998), Table 26.

45. Total natural gas consumption, which is end-use consumption plus lease and plant fuel, and pipeline fuel, was 21.4 trillion cubic feet in 1998. The highest level of total natural gas consumption ever recorded was 22.1 trillion cubic feet in 1972.

46. January and November, in particular, were warmer in 1998 than in 1997. Heating degree days were 18 percent lower in January 1998 than in January 1997 and 14 percent lower in November.

47. Energy Information Administration prices paid for natural gas in the electric utility sector are the average for all deliveries to the sector. However, prices paid for natural gas in the residential, commercial, and industrial sectors are for onsystem sales only. Nearly all deliveries are onsystem in the residential sector. During 1995 through 1997 (and for preliminary monthly data in 1998), onsystem sales were roughly 65 to 80 percent of commercial deliveries and roughly 15 to 25 percent of industrial deliveries.

48. Prices and expenditures were adjusted to 1998 dollars by the Energy Information Administration, Office of Oil and Gas, using chain-type price indices for gross domestic product from the U.S. Department of Commerce, Bureau of Economic Analysis Internet site <http://www.bea.doc.gov>, as of August 13, 1998, Table 7.1.

49. For a more detailed discussion of events during the 1996-97 heating season, see Energy Information Administration, "Natural Gas Residential Pricing Developments during the 1996-97 Winter," *Natural Gas Monthly*, DOE/EIA-0130(97/08) (Washington, DC, August 1997).

50. U.S. Department of Commerce, Bureau of the Census, Current Construction Reports— *Characteristics of New Housing*, 1996 and 1997, C25/96-A and C25/97-A (Washington, DC, June 1997 and July 1998), Table 10. Note that in these data, "gas" includes natural gas and propane.

51. Industrial consumption of natural gas in both 1996 and 1997 exceeded the previous peak of 8.7 trillion cubic feet set in 1973. Annual consumption data go back to 1930.

52. The estimated price paid by industrial users for natural gas in 1998 (through November) is applicable to only 15 percent of natural gas deliveries in this sector.

53. As determined by the National Bureau of Economic Research.

54. Original data on manufacturing production were the Manufacturing Indices, Code B00004, from the Internet site of the Board of Governors of the Federal Reserve System <http://www.bog.frb.fed.us/releases/G17/ipdisk/ip.sa>, as of January 19, 1999.

55. Energy Information Administration. Prior to 1992, data on nonutilities were collected for facilities of 5 megawatts or more. In 1992 the threshold was lowered to include facilities with capacities of 1 megawatt or more. Nonutility data for 1992 are from the *Annual Energy Review 1997*, DOE/EIA-0384(97) (Washington, DC, July 1998), Table 8.14. Information on cogeneration and nonutility data for 1993-1997 are from the *Electric Power Annual 1996*, Vol. II, DOE/EIA-0348(96/2) (Washington, DC, December 1997), p. 82, Figure 14 and Table 51.

56. That is, 18 percent of the natural gas that was delivered to industrial users was sold by the delivering company. This is referred to as "onsystem" gas. The other 82 percent was only transported by the delivering company, thus the company did not have information on the purchase price of the natural gas. This is referred to as "offsystem" gas.

57. In 1994, the industrial sector included manufacturing, mining, construction, and all nonutility generators of electricity.

58. Energy Information Administration, *Manufacturing Consumption of Energy 1994*, DOE/EIA-0512(94) (Washington, DC, December 1997), p. 16.

59. Information on manufacturer's use of natural gas is found in Energy Information Administration, *Manufacturing Consumption of Energy 1994*, DOE/EIA-0512(94) (Washington, DC, December 1997).

60. Distributed Power Coalition of America, Internet site <http://www.dpc.org/faq.html>, as of August 6, 1998.

61. "Gas" includes natural gas, refinery gas, blast-furnace gas, coke oven gas, and propane for data on net electricity generation and for retirements and additions of generation capacity.

62. Many of the nuclear plant outages extended through much of 1997 and were due to scheduled refueling, maintenance, or repair. Net electricity generation from coal also set a record in 1997. Energy Information Administration, *Electric Power Annual 1997*, Vol. 1, DOE/EIA-0348(97)/1 (Washington, DC, July 1998), p. 1 and Table 10.

63. Data on electricity generation capacity retirements and additions are from the Energy Information Administration's *Inventory of Power Plants in the United States: As of January 1, 1998*, DOE/EIA-0095(98) (Washington, DC, December 1998), Tables 1, 11-13, and 16.

64. Energy Information Administration, *Annual Energy Outlook 1999* (*AEO99*), DOE/EIA-0383(99) (Washington, DC, December 1998), Table A13. In the projections, natural gas used for the generation of electricity includes that used by electric utilities and nonutility generators except for cogenerators. In the data presented elsewhere in *Natural Gas 1998: Issues and Trends*, all nonutility consumption of natural gas is included in the industrial sector. Also, in the *AEO99*, 1997 data were based on preliminary estimates and 1998 is the first year of projected data.

65. Energy Information Administration, *Annual Energy Outlook 1999*, DOE/EIA-0383(99) (Washington, DC, December 1998), p. 72.

66. Energy Information Administration, *Annual Energy Outlook 1999*, DOE/EIA-0383(99) (Washington, DC, December 1998), National Energy Modeling System, reference case, run AEO99B.D100198A.

67. See Energy Information Administration, *The Changing Structure of the Electric Power Industry: Selected Issues, 1998*, DOE/EIA-0562(98) (Washington, DC, July 1998).

68. Barbara Shook, “CSWE Plans New Merchant Plant To Increase ERCOT Reliability,” *Natural Gas Week* (July 13, 1998), p. 8. “Capline’s Pasadena Power Plant Feeds Big, Hungry Texas Market,” *Natural Gas Week* (July 13, 1998), p. 11. “Duke to Build Merchant Plant To Serve Florida Power Market,” *Natural Gas Week* (August 24, 1998), pp. 14-15.

69. Distributed Power Coalition of America, Internet site <http://www.dpc.org/faq.html>, as of August 6, 1998. Distributed power technologies include “small combustion turbine generators, internal combustion engine/generators, photovoltaic solar panels, wind turbines, and fuel cells.”

70. For a discussion of these issues in the California market, see: California Alliance for Distributed Energy Resources, *Collaborative Report and Action Agenda* (January 1998).

71. Local distribution companies (LDCs) traditionally provided the commodity “bundled” with a package of related services, including interstate transportation, storage, and distribution service to all customers on its distribution system. In the early 1980s, large volume consumers were permitted access to service providers who operate outside the LDC’s service area or “offsystem.”

72. The Iowa Public Utility Commission adopted small customer unbundling in 1986, however, marketer and consumer participation has been slight. As a result, the commission did not renew the pilot program and is now considering further action.

73. This analysis is based on data from a variety of industry reports and information gathered by Energy Information Administration analysts. The principal reports used in this analysis are: *Energy Deregulation: Status of Natural Gas Customer Choice Programs*, Government Accounting Office (December 1998) and *Providing New Services to Residential Natural Gas Customers: A Summary of Customer Choice Pilot Programs and Initiatives 1998 Update*, American Gas Association Issue Brief 1998-03 (July 31, 1998).

74. A customer who lives in a State that has complete retail unbundling may not be eligible to select its natural gas provider if it resides in (1) a local jurisdiction that has decided not to institute customer choice, (2) a service area of an LDC that has not yet received approval to unbundle services by State regulators, or (3) an area where third-party providers have not offered service.

75. The estimated annual unbundled gas purchases are derived by multiplying the State’s average residential consumption (from EIA’s *Natural Gas Annual 1997*, DOE/EIA-0131(97)) by the number of residents participating in the respective State’s unbundling program. State levels are summed to arrive at regional amounts, and regional amounts are summed to arrive at national levels. Since actual unbundled purchases by residential customers are not available and many choice programs have been active for only a short time, the derived purchases are used to approximate customer activity.

76. According to the Government Accounting Office report, *Energy Deregulation: Status of Natural Gas Customer Choice Programs*, marketers are unable to compete with the low gas prices available in New Mexico.

77. The price a local distribution company (LDC) charges its customers for gas is reported to the State regulatory body and is commonly used as a benchmark by which marketer prices are compared. Marketers, as nonregulated entities, are not required to disclose their prices to regulatory bodies. The benchmark LDC prices may become less representative as customers move their purchases from LDCs to marketers.

78. Marketers are able to guarantee savings in most States because they are not required to pay the same State taxes that the local distribution companies pay.

79. “Discouraged by ‘Numbers Game,’ Texaco Exiting Retail Market,” *Natural Gas Week*, Vol. 14, No. 22 (June 1, 1998), p. 4.

80. Local distribution companies have traditionally been required to contract for large amounts of relatively expensive, firm transportation capacity to serve their retail customers.

81. For example, Massachusetts, New Jersey, and New York.

82. The proposed "Certified Energy Marketer" (CEM) seal would be an indication to consumers that the marketer has agreed to operate by a series of fair marketing practices and is committed to providing reliable service. These standards are intended to protect residential and commercial customers in both the natural gas and electricity markets and to promote competition and integrity of emerging gas markets.

83. Marketer in this context refers to marketers, aggregators, or suppliers, including utility affiliates marketing or otherwise selling natural gas (or electricity) and arranging for interstate transportation or transmission capacity to residential and commercial customers eligible to participate in customer choice programs.

84. According to Southwest Research Institute, "a locomotive engine that produces approximately 12 grams of nitrogen oxides per horsepower hour (g/bhp-hr) using diesel fuel only produces 2.8 g/bhp-hr using this new liquefied natural gas (LNG) engine technology. Southwest Research Institute (SWRI) News, "*GasRail USA reduces Nox by 75 percent*" News Release (May 29, 1998). (Http://www.swri.org/9what/releases/rail.htm)

85. "ARCO,SYNTROLEUM begin joint development of synfuels reactor technology: ARCO to build pilot-scale plant facility on West Coast," Press Release (October 24, 1997).

86. "New Combustion Technology Facilitates Smaller Capacity GTL Plants," Syntroleum Corporation Press Release (September 16, 1998).

87. "DOE selects research partner for project to make liquids from natural gas," *DOE Fossil Energy Techline* (May 20, 1997).

88. "GTL technologies focus on lowering costs," *Oil and Gas Journal* (September 21, 1998), Vol. 96, No. 38, p. 76.

89. For example, Statoil, Texaco, Marathon, and Conoco.

90. The full fuel-cycle analysis includes the carbon dioxide released from actual use of fuel in the vehicle as well as the additional gases released during the finding, manufacture, and transport of the fuel.

91. Energy Information Administration, *Annual Energy Outlook 1999*, DOE/EIA-0383(99) (Washington, DC, December 1998).

92. The "Annex I" countries include: Australia, Austria, Belgium, Bulgaria, Canada, Croatia, Czech Republic, Denmark, Estonia, European Community, Finland, France, Germany, Greece, Hungary, Iceland, Ireland, Italy, Japan, Latvia, Liechtenstein, Lithuania, Luxembourg, Monaco, Netherlands, New Zealand, Norway, Poland, Portugal, Romania, Russian Federation, Slovakia, Slovenia, Spain, Sweden, Switzerland, Ukraine, United Kingdom of Great Britain and Northern Ireland, and the United States of America. Turkey and Belarus are Annex I nations have not ratified the Convention and have not committed to quantifiable emissions targets.

93. The report *Impacts of the Kyoto Protocol on U.S. Energy Markets and Economic Activity* (*Kyoto*), SR/OIAF/98-03 (Washington, DC, October 1998), examines a series of six cases looking at alternative carbon levels. The reference case represents projections of energy markets and carbon emissions without any enforced reductions and is presented as a baseline for comparison of the energy market impacts in the reduction cases. The most extreme case examined is the "7 Percent Below 1990 Level" (1990-7%), which essentially assumes that the 7-percent target in the Kyoto Protocol must be met entirely by reducing energy-related carbon emission, with no net offsets from sinks, other greenhouse gases, or international activities. The highest consumption patterns for natural gas are seen in some of the intermediate cases, principally the "Stabilization at 1990 Levels" and the "3 Percent Below 1990 Levels."

    The reference case used for the *Kyoto* report is different from the *AEO99* reference case. The results for 2010 and 2020 are very similar for the natural gas sector (usually within 2 to 3 percent for the major variables). Because of these differences, the discussion generally focuses on differences from the reference case. When volumes are used, they are generally cited as ranges.

94. To reduce emissions, a carbon price is applied to the cost of energy. The carbon price is applied to each of the energy fuels relative to its carbon content at its point of consumption. Electricity does not directly receive a carbon fee; however, the fossil fuels used for generation receive the fee, and this cost, as well as the increased cost of investment in generation plants, is reflected in the delivered price of electricity. In practice, these carbon prices could be imposed through a carbon emissions permit system. In this analysis, the carbon prices represent the marginal cost of reducing carbon emissions to the specified level, reflecting the price the United States would be willing to pay in order to purchase carbon permits from other countries or to induce carbon reductions in other countries. In the absence of a complete analysis of trade and other flexible mechanisms to reduce international carbon emissions, the projected carbon prices do not necessarily represent the international market-clearing price of carbon permits or the price at which other countries would be willing to offer permits.

The Energy Information Administration analysis assumes that the Government would hold an auction of carbon permits. The cost of the permits is reflected in energy prices, and the revenues collected from the permits are recycled either to individuals by means of an income tax rebate or to individuals and businesses through a social security tax rebate.

In 2010, the carbon prices projected to be necessary to achieve the carbon emissions reduction targets range from $67 per metric ton (1996 $) in the "1990+24%" Case to $348 per metric ton in the "1990-7%" Case.