

Executive Summary

Natural Gas 1998: Issues and Trends examines the current natural gas marketplace from a series of vantage points, providing insight into continuing and developing trends and a look at market and regulatory issues that have emerged as the industry has had to adapt to a growing and changing economy. A major issue that has emerged over the past several decades, and which is becoming closely integrated with natural gas growth, is its role in meeting future environmental concerns.

From 1990 through 1998, natural gas consumption in the United States increased by 14 percent. Its greater use as an industrial and electricity generating fuel can be attributed, in part, to its relatively clean-burning qualities in comparison with other fossil fuels. Lower costs resulting from greater competition and deregulation in the gas industry and an expanding transmission and distribution network have also helped expand its acceptance and use.

Several trends cited in this study indicate a substantial expansion of the natural gas market. Transmission deliverability on the national network has grown significantly since 1990 and greater investment for expansion is expected over the next several years. A steady growth in upstream supply, especially in the Gulf of Mexico and from Canada, and increased levels of consumption in all regions of the country, primarily in the industrial and electricity generation sectors, have motivated these expansions.

Use of Natural Gas To Address Electricity Growth Is Key to Gas Industry Expansion After 2000

In 1998, the parties to the Kyoto Protocol to the U.N. Climate Change Convention recommended measures aimed at decreasing the global level of greenhouse gases. Implementation of the Kyoto Protocol, or its recommendations as working parts of an accepted global effort, remains uncertain. However, it seems certain that natural gas will be a key factor in efforts to improve overall global environmental conditions.

While environmental concerns could drive expansion of the use of natural gas, the direction of the natural gas marketplace in the near term generally will be determined more by traditional economic forces. Evolution of a restructured and more competitive natural gas industry

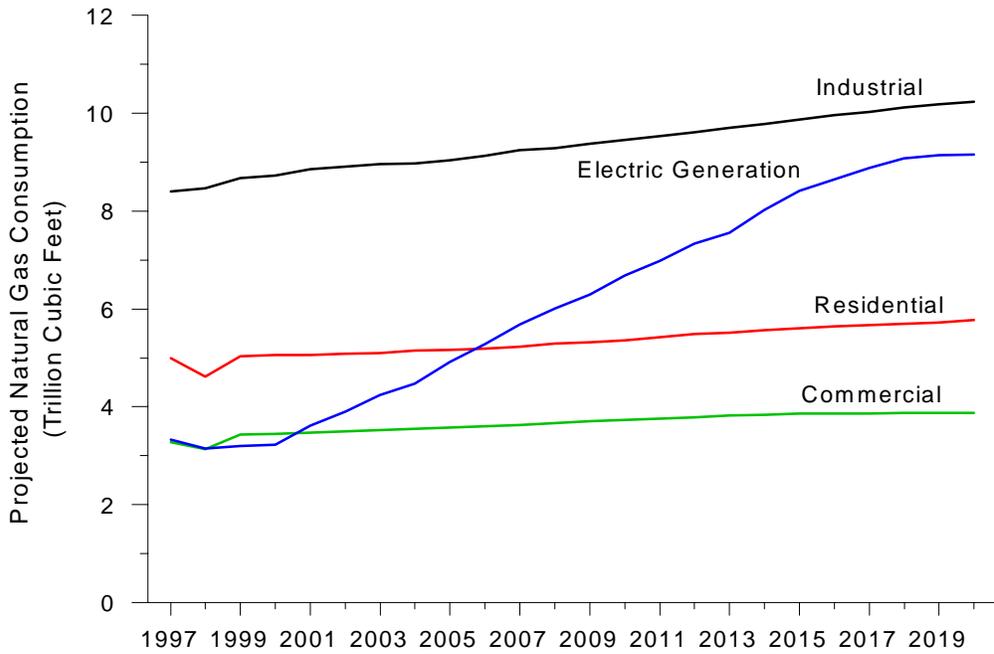
during the past 10 years has been partly responsible for lower overall prices for natural gas. This trend of low prices could continue as long as demand does not outpace supply, the delivery system for natural gas grows, and enough capital investment is forthcoming to support expected growth.

Industrial consumption of natural gas reached an historic peak of 8.9 trillion cubic feet (Tcf) in 1996 but has declined somewhat since then. In 1998, the industrial sector consumed an estimated 8.5 Tcf, accounting for 44 percent of all end-use consumption, the largest share of any sector. Roughly one-quarter of the natural gas used by the industrial sector is consumed by companies that have been classified as nonutility generators (NUGs). Most NUGs are cogenerators, although this classification also includes independent power producers whose consumption of natural gas is solely for generation of electricity. By contrast, cogenerators typically use the heat from natural gas combustion both in manufacturing processes and to generate electricity. From 1992 through 1997, nonutility natural gas consumption accounted for 25 to 28 percent of total industrial consumption. Nonutility consumption grew at an annual rate of 4 percent from 1992 through 1997, while total industrial consumption increased at a 3-percent annual rate.

Electric utilities are expected to be the only end-use sector that increased its consumption of natural gas from 1997 to 1998, according to preliminary estimates. Data 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 by electric utilities in 1998, available through October, was 13 percent below that in 1997. Annual natural gas consumption by electric utilities during the 1990s has been in the range of 2.7 to 3.2 Tcf.

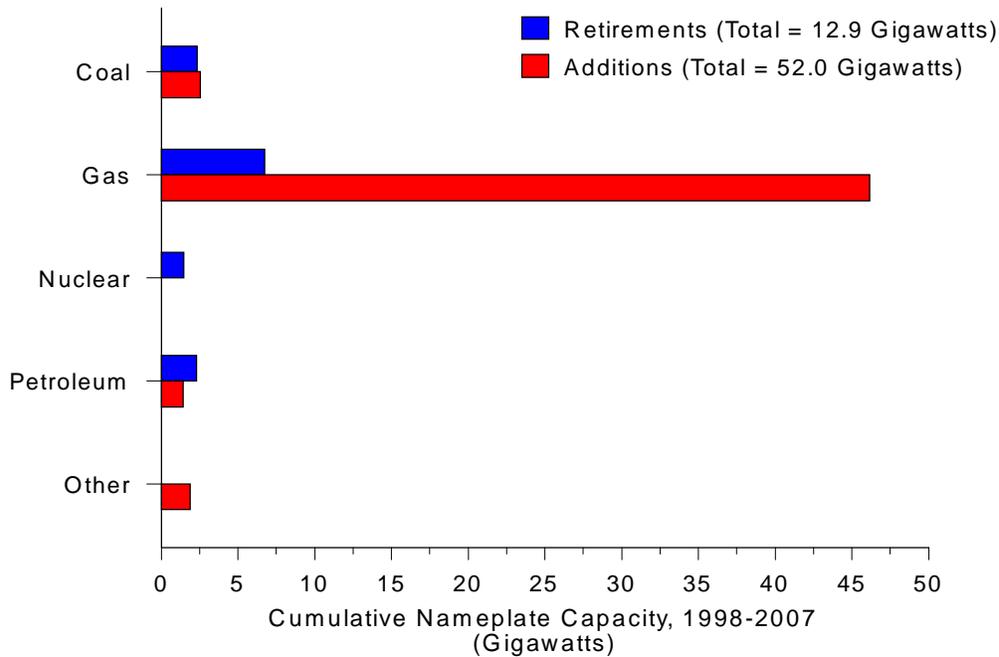
A major contributor to the increasing use of natural gas in the electric utility sector is the lower capital costs and shorter construction lead times of advanced combined-cycle plants in comparison with conventional coal-fired plants. Part of the push for lower-cost generation and shorter construction lead times can be attributed to the impact of the restructuring of the electric generation and transmission industry, particularly in light of growing electricity demand and the continued retirement of nuclear plants.

Figure ES1. Strong Growth in Natural Gas Usage Is Projected in Electricity Generation



Source: Energy Information Administration, *Annual Energy Outlook 1999*, National Energy Modeling System run AEO99B.D100198A.

Figure ES2. Most Electric Generation Capacity Additions Will Be Gas-Fired



Notes: "Gas" is natural gas; refinery, blast-furnace, and coke-oven gases; and propane. Other consists mostly of waste heat and includes renewables, most of which is hydroelectric power.

Source: Energy Information Administration, *Inventory of Power Plants in the United States As of January 1, 1998*.

Natural gas use by electric utilities and NUGs to generate electricity is projected to reach 9.2 Tcf by 2020, a little more than three times the 1998 level (Figure ES1). A principal factor in this is that nearly all future electric utility capacity additions in the United States are expected to be fueled by natural gas (Figure ES2). A growing trend in the development of gas-fired electric generation is the evolving independent (“merchant”) power plant sector of the electric industry. These enterprises, which are expected to be primarily gas-fired facilities, are built without prior long-term sales commitments and therefore are very dependent upon fuel efficiencies and energy market economics.

Gas Resources Are Substantial But Continued Supply Growth Is Unlikely Without Price Recovery

While domestic natural gas production generally increased from 1994 through 1997, reserve additions replaced nearly 107 percent of production, arresting a long-term decline in total proved reserves. The majority of proved gas reserves in the Lower 48 States are located in the onshore and offshore Gulf Coast region, an area that is characterized by expanding development of the Outer Continental Shelf. Natural gas reserves in the Gulf region now represent 51.6 percent, or 80.9 Tcf, of proved reserves in the Lower 48 States.

Natural gas production in 1998 is estimated to be 19.0 Tcf, essentially the same as in 1997, despite lower overall demand. In 1997, natural gas from onshore conventional sources accounted for the largest share of U.S. production, about 39 percent, while production from onshore unconventional sources, such as coalbeds, Devonian shale, and tight sands, accounted for 19 percent. Production from unconventional sources became the largest contributor to increased natural gas production during the 1990s, growing at an annual rate of 4 percent between 1990 and 1997.

Natural gas well completions increased to nearly 12,000 in 1997. Generally higher wellhead prices in 1997, averaging \$2.34 per thousand cubic feet compared with \$1.62 in 1995 (prices in constant 1998 dollars), served as an incentive for increased drilling. Completions increased 8.9 percent in 1998 to 11,907; however, monthly completions declined during the year as wellhead prices fell to near or below \$2.00 per thousand cubic feet in most months. The even greater fall in oil prices during 1998 helped redirect resources toward gas, thus supporting the higher gas well count for the year.

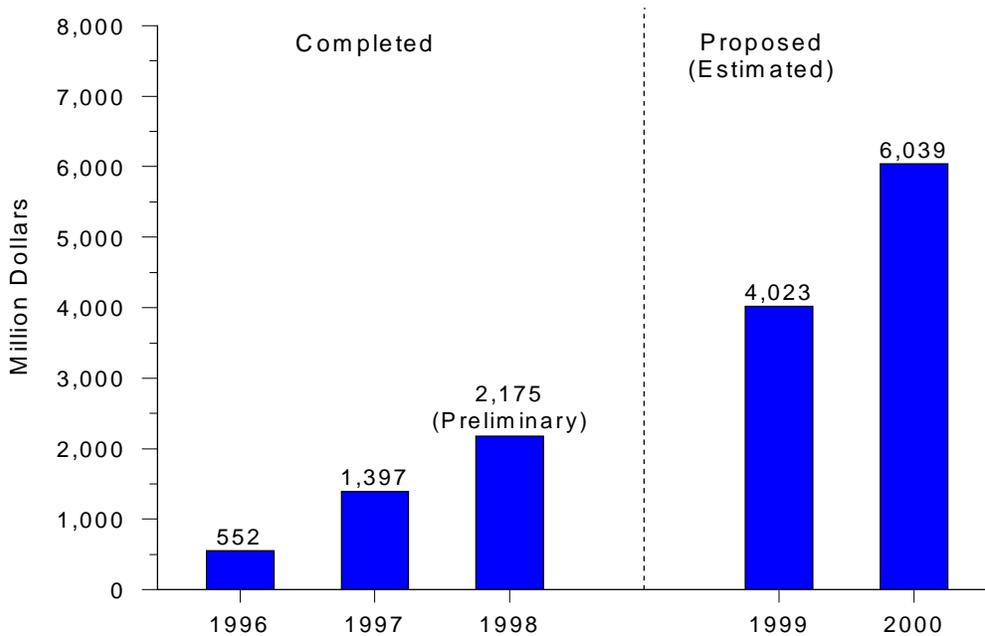
End-use natural gas consumption reached a record high of 20.0 Tcf in 1996 and 1997, then declined 4 percent in 1998 to 19.3 Tcf. After 7 years of sustained growth, natural gas consumption in 1998 fell below its previous year level for the first time this decade. Relatively mild weather throughout the year across most of the Lower 48 States can be cited as the primary cause for the reduced demand in the residential and commercial sectors. The net consumption falloff, along with abundant foreign supplies to the United States and competition driven by the overall slump in petroleum prices, resulted in a significant drop in natural gas prices.

The weather situation also resulted in lower withdrawals from storage during the 1997–98 heating season, and by its close, the remaining working gas storage level was 1.2 Tcf, the highest end-of-season level in 3 years. Reduced demand for storage replenishment created an additional downward pressure on prices since the lower market demand increased gas-on-gas competition (between supplies normally flowing into storage and normal seasonal base-load supplies). Wellhead prices fell about 15 percent in 1998 compared with 1997 levels, contributing to price drops of 1 and 5 percent in the residential and commercial sectors, respectively, and 12 and 13 percent (estimated) in the industrial and electric utility sectors.

The current low levels for natural gas prices could have a longer-term impact on natural gas exploration, development, production, and even anticipated pipeline expansions. Lower oil prices have dampened oil drilling activities and thus have affected the future production levels of natural gas associated with oil production. Lower natural gas prices and demand could create similar fallout in the gas industry. If natural gas demand growth levels off, then it is likely that some proposed pipeline expansions, especially those into highly competitive markets, might be postponed or even canceled.

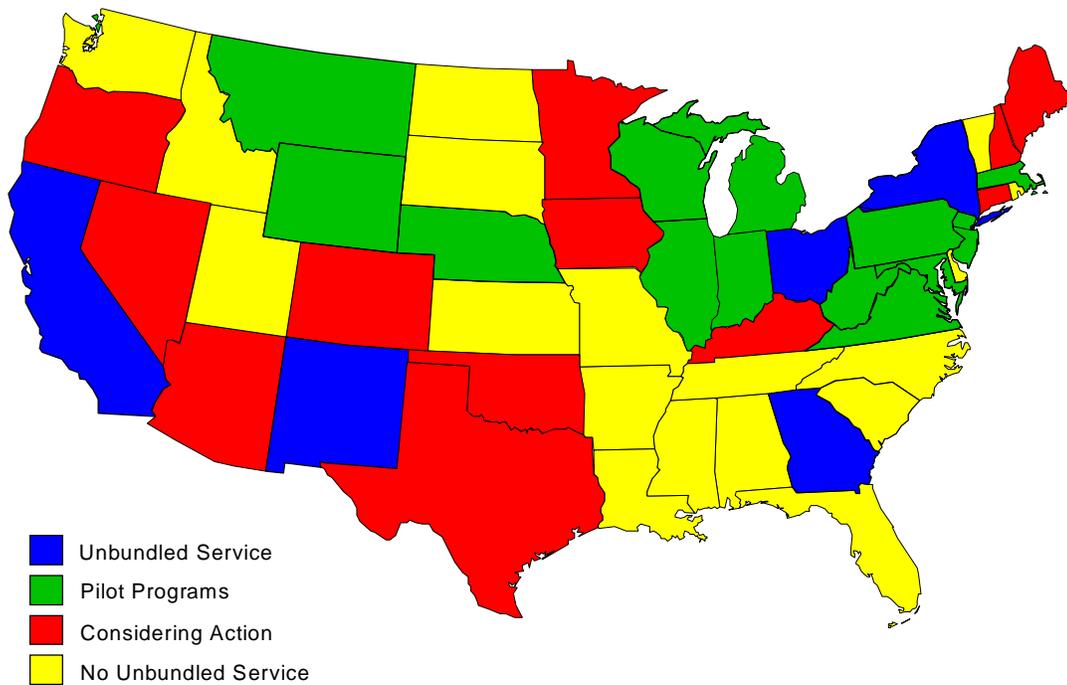
The potential for bountiful long-term natural gas supplies is strong in light of the expected remaining recoverable U.S. gas resources. These include 167 Tcf in proved natural gas reserves at the end of 1997 and roughly 1,300 Tcf as technically recoverable natural gas resources. In addition, Earth’s vast deposits of natural gas hydrates would provide a very significant new source of natural gas if future technology should enable the commercial recovery of the methane in these deposits. Natural gas hydrates are solid, crystalline, ice-like substances composed of water, methane, and usually smaller amount of other gases. The

Figure ES3. Annual Pipeline Investment Could Reach \$6 Billion in 2000



Source: Energy Information Administration, Office of Oil and Gas, Natural Gas Pipeline Construction Database through December 1998.

Figure ES4. Eighteen States and the District of Columbia Have Some Form of Residential Choice Program



Source: Energy Information Administration (EIA), Office of Oil and Gas, derived from General Accounting Office, *Energy Deregulation: Status of Natural Gas Customer Choice Programs* (December 1998) and information gathered by EIA analysts.

naturally occurring version is primarily found in ocean-bottom sediments at water depths that exceed 450 meters (approximately 1,476 feet) and in permafrost regions onshore. The U.S. Geological Survey's 1995 mean (expected value) estimate is that in aggregate these deposits contain 320,222 Tcf of methane-in-place. Even if only a small percentage of the large in-place volume could be commercially produced, the impact would be dramatic. Recovery of only 1 percent of the hydrate resource would more than double the domestic gas resource base.

Significant Pipeline Expansion and Investment Will Be Needed To Support a Projected 32 Tcf Market

Interstate pipeline capacity has increased by more than 16 percent (on an interregional basis) during the past decade. Average daily use of the network was 72 percent in 1997, compared with 68 percent in 1990. More than 17 new interstate pipelines were constructed, as well as numerous expansion projects, between 1990 and the end of 1998. In 1998, at least 47 projects were completed adding approximately 10 billion cubic feet (Bcf) per day of overall capacity to the national grid.

For 1999 and 2000, more than 75 pipeline projects (20.1 Bcf per day) have been proposed for development in the Lower 48 States. While some of these projects are only in the initial planning stage with no firm cost estimates available, based upon preliminary estimates, as much as \$10.0 billion could be spent on natural gas pipeline expansions in the next 2 years (1999–2000) (Figure ES3). The largest expenditures, about \$6.0 billion, would include several large projects now scheduled for completion in 2000, such as the Alliance Pipeline (\$2.9 billion), the Independence Pipeline (\$680 million), and the Columbia Gas System's Millennium project (\$678 million). In all likelihood, however, some of the 75 proposed projects may be canceled or postponed until the next decade, because of competition, changed market conditions, and/or regulatory actions.

A major factor underlying the network expansion is the growing availability of new production from Canada. U.S. access to Canadian supplies, as measured by crossborder pipeline capacity, increased by 75 percent (from 6.5 to 11.4 Bcf per day) between 1990 and 1997 and by another 9 percent, or 997 million cubic feet per day, in 1998. An additional 3.7 Bcf per day of capacity could be in place by 2000 if all currently planned projects are completed. This would amount to a 132-percent increase in import capacity between 1990 and 2000. Put another way, capacity to import gas from Canada in 1990 was only 19 percent as

large as capacity to export gas from the U.S. Southwest, the major producing region in the United States. But by the end of 2000, import capacity from Canada could be as much as 42 percent of the Southwest's export capacity.

Regulatory Reform Has Altered Markets at Both the Interstate and State Levels

Numerous transportation service contracts written prior to market regulatory reform contain terms and conditions that are no longer deemed economic by shippers. Consequently, some of the contracts are not being renewed or the terms are being revised upon renewal. Some firm capacity is being "turned back" to the pipeline company. It is estimated that 20 percent of firm service capacity under these older contracts has not been renewed. Some of this capacity has been resold, but a significant amount remains uncommitted or has been resold at discounted rates, which could impede the pipeline companies' cost recovery. Costs not recovered from new customers then fall on either the remaining pipeline customers or the shareholders. Potential capacity turnback actions between 1998 and 2003 represent about 8.0 trillion Btu per day, or 8 percent of currently committed capacity. If the capacity is not remarketed at maximum rates, pipeline company revenues could be reduced.

State unbundling of services continued in 1998 although at a relatively slow pace. As of July 31, 1998, only five States had implemented complete unbundling programs for core customers (Figure ES4) or passed legislation to give customers the right to choose their own gas supplier, only two more than at the end of 1996. The approximately 14 million residential customers covered in these States represent about 20 percent of the Nation's natural gas customers. Another 13 States and the District of Columbia have pilot programs underway, 12 States are considering action, and 18 States have yet to take any significant action.

Corporate Combinations Are Reaching All-Time Highs as Companies Look for Opportunities in Both Gas and Electricity

A number of major market participants are engaging in various forms of corporate combinations, such as mergers, acquisitions, and strategic alliances. The value of mergers and acquisitions within the natural gas industry has risen nearly fourfold in this decade, from \$10.4 billion in 1990 to \$39 billion in 1997. This increase parallels an enormous surge in corporate combinations (mergers, acquisitions, joint ventures, and strategic alliances) across the energy sector, from \$21.4 billion in 1990 to \$106.4 billion in 1997. In 1998, the value of energy sector combinations more than

doubled, to \$220 billion, with the announcement of such blockbuster mergers as British Petroleum with Amoco and Exxon with Mobil.

The growth in natural gas industry combinations does not indicate a decrease in competition, however. For example, between 1992 and 1997, the share of sales by the top four marketers declined by one-third to 21 percent, while their sales volumes more than doubled. Sales by the top 20 slipped only from 69 to 66 percent, but yearly sales volumes more than tripled to 40 Tcf.

The current wave of corporate combinations appears set to continue as companies throughout the energy sector jockey for position not only in North America but worldwide with both the number and size of combinations increasing. Nevertheless, combinations in the energy sector remained a relatively small part of corporate combinations for the United States in general, representing only about 11 percent of the total value of all combinations in 1997.

Corporate combinations in the natural gas industry have become an integral part of the strategies developed to address changing conditions in the industry. Specific objectives behind the combinations vary, but many combinations share the goal of expanding beyond a single commodity or a single function to encompass a broad spectrum of energy sources, products, and services, thus becoming a "one-stop energy center."

Outlook

U.S. reliance on fossil hydrocarbon fuels (mainly coal, natural gas, and petroleum products) is projected to increase during the next two decades. In 1997, 85.3 percent of the domestic energy was produced by fossil fuels. By 2020, fossil fuel usage is expected to account for 89.7 percent of domestic energy production with 28 percent attributable to natural gas. Concurrent projections also are that natural gas consumption will move above the historical peak of 22 trillion cubic feet (Tcf) (reached in 1972) in 1999, increase another 6 Tcf by 2010, and reach 32 Tcf by 2020. This

growth is expected to come about largely as a result of increased use of natural gas for electricity generation by both electric utilities and nonutility generators.

The expected use of natural gas could become higher than current projections if the United States were to adopt the Kyoto Protocol. The agreement would specify a greenhouse gas target during the commitment period 2008 to 2012 that, on average, would be 7 percent below 1990 levels, or about 1,250 million metric tons. Natural gas use would likely expand while coal and oil consumption and production would decrease, primarily because the carbon content per Btu of natural gas is only 55 percent of that for coal and 70 percent of that for oil. Under the protocol, natural gas consumption would be 0.6 to 3.5 Tcf higher by 2010 under a number of alternative scenarios.

A major amount of new pipeline capacity is expected to be built over the next several years to accommodate projected growth. In addition, complementary facilities, such as market centers and storage facilities, are also expected to expand to support it. Although only a few new market centers are likely to become operational during the next few years, the services and flexibility offered at many existing sites can be expected to be expanded and improved, especially those located in the Midwest and Northeast that could support the expanded growth of Canadian supplies. Underground storage operations, which facilitate both market center services and efficient pipeline operations, will also be selectively expanding over the next several years although not at the scale seen earlier in the decade. A number of the major proposed pipelines slated to carry additional gas from Canada and the Midwest are associated with already scheduled storage expansions.

Not only have the capabilities of the natural gas production, transmission, and distribution network grown significantly since 1990, but the quality and flexibility of service have improved as well. Additional substantial growth and improvement are expected over the next several years. Expanding interconnectivity within the pipeline grid, accompanied by improved services, will further integrate the natural gas production and delivery system, thereby helping to accommodate anticipated future demand.