1. Overview

During the past 20 years, the natural gas industry has seen the gradual decontrol of natural gas wellhead prices and the unbundling of pipeline company transportation and sales services. The industry has responded to these changes by entering into new contractual relationships, developing new services and new tools for managing risk, and even creating a new industry participant—the natural gas marketer.

Change continues at a rapid pace as supply prices are becoming more volatile, unbundling is entering into local distribution, and new entities are forming to deal with the impact of the restructuring that is beginning in the electric industry. This report reviews the many choices and challenges facing participants in today's natural gas market. It analyzes how different segments of the industry are reacting to the more open and flexible business environment, and it points out those issues that will have a significant impact on the industry in the future.

Chapter 1 reviews the basic data series commonly used to evaluate the natural gas industry and summarizes some of the key issues faced by the industry today. Other chapters of the report provide analyses in greater depth on recent changes in the industry and major challenges for the future.[1]

- Chapter 1 is divided into two sections. The first section, "Data Trends," provides a quick overview of such data series as price, supply, transportation, and consumption. The second section, "Key Issues," contains information on subjects that go beyond the basic data series and are of particular interest as the natural gas market continues to evolve. Topics in this section include the industry response during recent periods of cold weather; mergers and acquisitions; recent regulatory changes; developments in offshore, deep water production; a review of electronic information systems; and a summary of some potential effects of electric industry restructuring on the natural gas industry.

- Chapter 2 examines issues in the transportation of natural gas, analyzing patterns in capacity release and capacity turnback. Shippers continue to move more gas under the various types of firm service that are available rather than under interruptible service. Yet the amount of firm capacity that is offered on the capacity release market indicates that shippers are holding a substantial amount of excess firm capacity. The issue of shippers turning back part of their firm capacity rights to pipeline companies will likely extend beyond the West and Midwest regions where such turnbacks are currently taking place.

- Chapter 3 looks at market centers and describes how various parties are using these relatively new elements of the industry to move gas more effectively. Market centers offer shippers a wide variety of services, such as transportation between pipelines, short- and long-term storage, and the buying and selling of gas. The development of market centers has changed the way many end users and marketers acquire gas. Better real-time, public information on prices will make these centers even more useful to a wider set of customers.

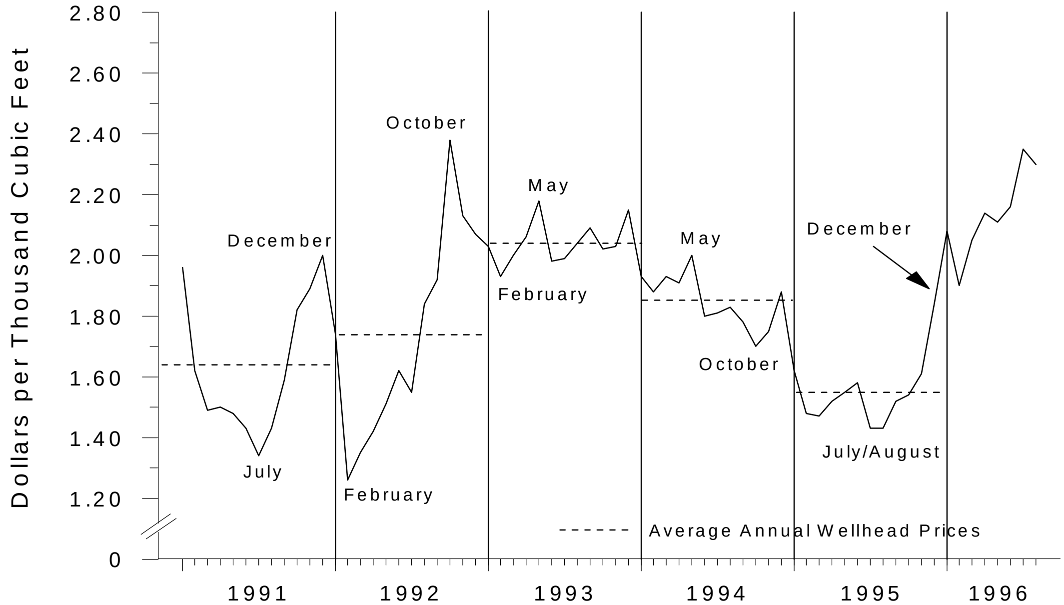
- Chapter 4 describes how producers are responding to changes in the marketing of natural gas. Included are the issues of contracting practices, technological advances, and new corporate strategies to expand marketing operations. The strongest challenges to producers are in the areas of cost containment and dealing with natural gas marketing, which is expected to change substantially as the electric industry goes through restructuring.

- Chapter 5 examines the pattern of consumer prices between 1990 and 1995. Natural gas prices declined in all end-use sectors during this period, but by varying degrees. The chapter examines price changes by region to identify patterns underlying these price declines. Price changes are discussed in light of the level of service required for each sector and other events in the natural gas industry from 1990 through 1995. The degree of price reductions in the future will be affected by the extension of unbundling to local markets, efficiency improvements in gas delivery systems, and competition from other fuels.

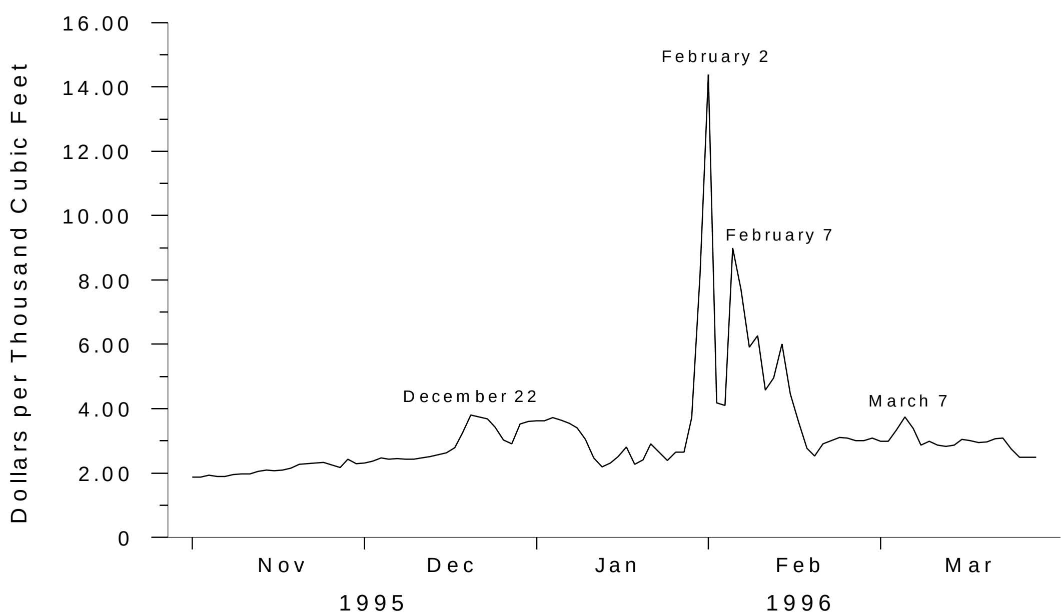
- Chapter 6 describes the progress being made in bringing the regulatory changes seen in the interstate market down to the level of local distribution. Numerous questions must be answered by State regulators as they attempt to bring the benefits of wider service options to residential and small commercial users. Among the questions is how to ensure service reliability while bringing the benefits of competition and choice to consumers. The separation of local sales and transportation has already begun in several States. Each State must consider carefully the details of local patterns of gas use and competition among gas suppliers as it develops its own plan for expanded retail services.

Figure 1. Increased Price Volatility Has Become Common in the Gas Industry

Wellhead prices vary greatly between months and years . . .



. . . and changes in daily spot prices at the Henry Hub can be extreme



Notes: All prices are in nominal dollars. In the wellhead price graph, the labeled months are the month of the maximum and minimum prices in each year.

Sources: **Wellhead Prices:** Energy Information Administration. 1991-1992—*Historical Monthly Energy Review*, *1973-1992*. 1993—*Natural Gas Monthly* (March 1996). 1994-August 1996—*Natural Gas Monthly* (November 1996). **Henry Hub Spot Prices:** Pasha Publications, Inc., *Gas Daily*.

Data Trends: Wellhead and Spot Prices

After a steep decline in 1995, natural gas spot and average wellhead prices moved sharply higher in 1996. Wellhead prices in 1995 averaged $1.55 per thousand cubic feet (Mcf), down 16 percent from the 1994 level of $1.85 per Mcf. In July and August 1995, prices bottomed out for the year at $1.43 per Mcf and then climbed to $1.84 per Mcf in December. Prices rose even higher in January 1996 and have stayed above the December 1995 value throughout 1996. The particularly high price of $2.35 per Mcf in July 1996 was in part due to strong demand for gas from storage customers who found their stocks badly depleted after the cold winter of 1995-96 and continued cold weather in early spring 1996.

Daily spot prices at the Henry Hub, a major exchange point for natural gas in South Louisiana, reached record levels during 1996. On February 2, 1996, some buyers paid more than $15.00 per Mcf, and the median price for the day was about $14.00.[2] The sharp rise and fall in price around this date indicates the phenomenal short-term price volatility in the natural gas marketplace. This volatility also surfaced in late November 1996 when prices at many trading locations and the Henry Hub futures market increased by more than $1.00 within one week. In fact, spot prices for December 1996 are likely to be between 25 to 50 percent higher than the December 1995 values. It is increasingly apparent in the gas market that wellhead prices no longer exhibit any systematic changes between years, daily price volatility is significant, and natural gas prices are becoming ever more difficult to predict.

- **Average annual wellhead prices in recent years have exhibited no obvious trend between years.** Wellhead prices averaged $1.55 per Mcf in 1995, which is the lowest annual value since 1979 and well below the peak during the 1980's of $2.66 per Mcf in 1984 ($3.77 in 1995 dollars). The mild 1994-95 winter, combined with plentiful supplies and relatively weak demand to refill storage reservoirs, contributed to the low price. Thus far in the 1990's, the differences between annual average prices have been as high as $0.30 per Mcf (nominal), or about $6 billion when expressed in terms of recent domestic production.

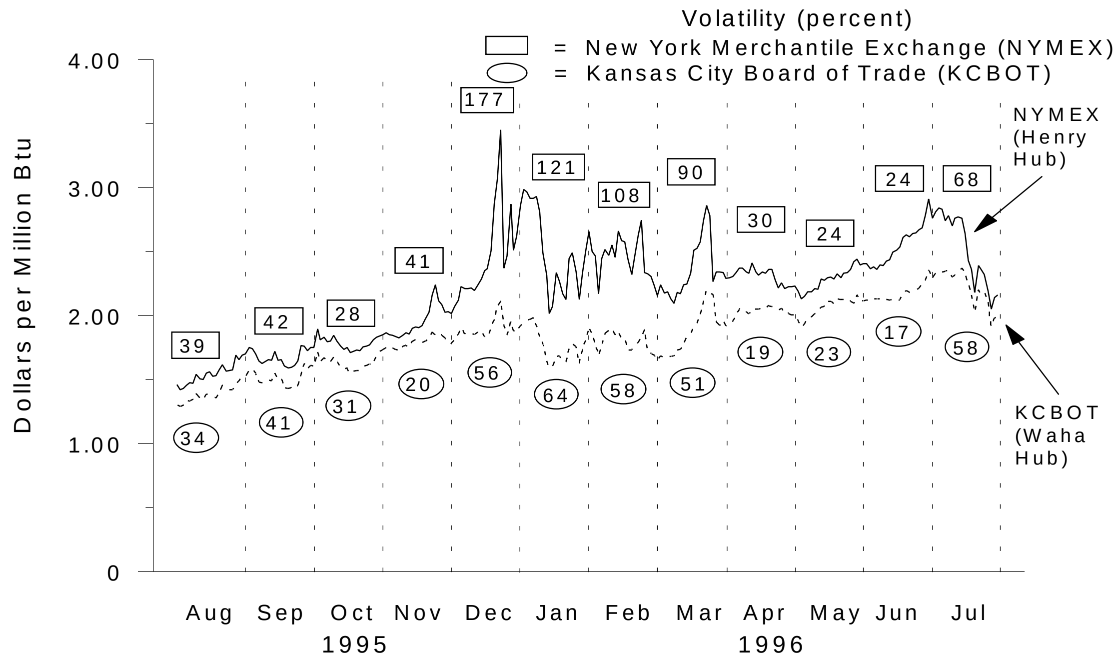
- **The wide variations in wellhead prices from month to month since 1991 (Figure 1) suggest that those sellers who can quickly bring additional gas supplies to market have much to gain when prices rise**. Since 1991, monthly changes in wellhead prices have at times been large and almost always difficult to predict based on historical data.[3] In addition, it is difficult to predict which month will have the lowest or highest prices during the year. The lowest monthly price occurred in February twice, yet it also occurred in the summer (1991 and 1995) and in the fall (1994). The highest monthly prices fell in three different seasons during this 5-year period. For 1996, preliminary estimates through August are all above the 1995 high of $1.84 in December. These higher prices were driven, in part, by persistently colder-than-normal temperatures in the heating season and relatively high storage injection levels during the nonheating season.

- **Spot prices at the Henry Hub varied widely between days during the 1995–96 heating season.** During December 1995, spot prices increased $1.36 in less than 10 days, from $2.44 to $3.80 per Mcf (Figure 1). Prices rose in response to colder-than-normal temperatures, lower-than-normal storage levels, and uncertainty about expected demands during the winter holiday season.[4] Prices stayed high until mid-January when they dropped by more than $1.00 in just a few days to settle at $2.19 per Mcf. Spot prices rose again in late January. By February 1, 1996, prices were above $4.00 per Mcf and stayed above $4.00 until February 19. With this extreme short-term price volatility, the inherent risk in holding stocks is great, but so are the opportunities if companies stay current on price fluctuations and maintain flexible operating and contracting practices.

- **The unpredictability of price provides a constant challenge to the industry.** Many companies have reduced the amount of working gas they have in storage sites, especially relative to current demand. Technologies have allowed companies to reduce the amount of gas they have in storage at any point in time yet still maintain deliverability. This change in industry practice increases price uncertainty during periods of consistently colder-than-normal temperatures, as in the 1995–96 heating season. However, increased use of salt storage and new technologies, such as the use of horizontal wells in conventional oil and gas storage reservoirs, enable the industry to bring larger amounts of incremental supplies of gas to markets sooner than in the past. In addition, the industry is better able to tradeoff higher gas prices with lower prices for transportation and storage service or vice versa.[5] The industry is also able to reduce price risk by using futures contracts and other financial instruments.[6]

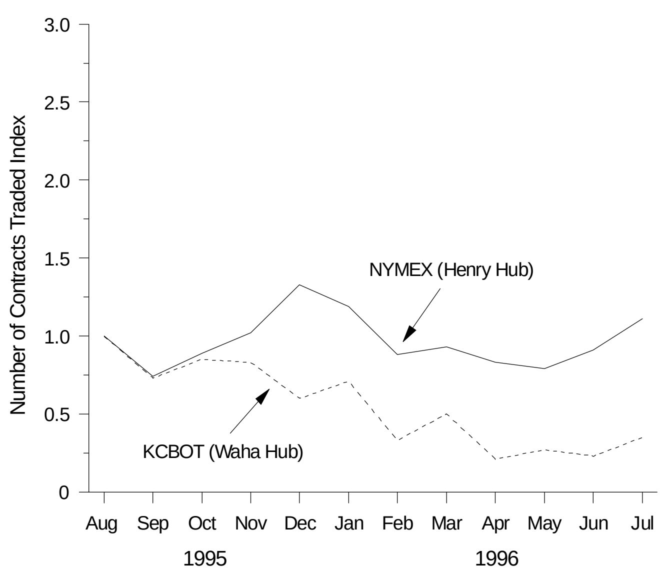
Figure 2. A Second Futures Market Began Trading in August 1995

Prices on both futures markets became more volatile in mid-December 1995

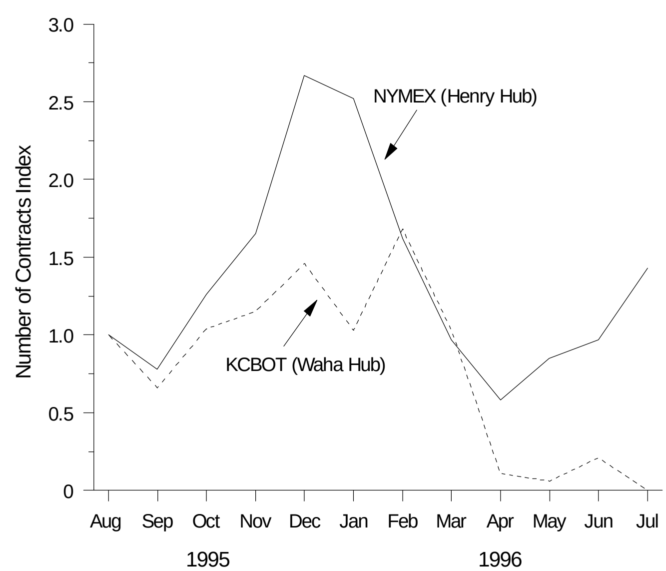


This increased volatility was coupled with increased trading on the NYMEX futures and options markets

Futures Markets



Options Markets



Note: In the price graph, "Volatility" is the annualized standard deviation of daily price changes expressed in percentage terms. The data are annualized by multiplying the standard deviation by the square root of 250, the number of trading days in a year.

Source: Energy Information Administration, Office of Oil and Gas, derived from Commodity Futures Trading Commission, Division of Economic Analysis.

Data Trends: Futures and Options

The high variability in natural gas supply prices and the large differences between eastern and western spot markets led to the establishment of a new futures contract in August 1995 by the Kansas City Board of Trade (KCBOT) for delivery though the Waha Hub in West Texas. The well-established New York Mercantile Exchange (NYMEX) futures contract for delivery at the Henry Hub in Louisiana is more closely connected to eastern consuming markets. In June 1996, NYMEX opened a competing western contract for delivery through the Permian Basin Pool, also in West Texas. Another NYMEX futures contract also began trading the last week of September 1996 for delivery in Alberta, Canada, to correlate more closely with Canadian spot prices and the U.S. markets served by Canadian natural gas.

The different prices and trading volumes of the Henry Hub and Waha Hub futures contracts since August 1995 (Figure 2) highlight the differences in eastern and western markets, particularly during the 1995-96 winter. At that time, cold weather and low storage levels in the East raised concern about supply deliverability, whereas temperatures in western markets tended to be above normal and storage levels were "normal." In general, the Henry Hub contracts had much higher prices and higher price variability, which was coupled with a higher volume of trade. The Henry Hub and Waha markets for options contracts, which provide rights to buy or sell a futures contract, both had substantial activity.

- **Prices for the nearby contract (the one next to expire) on both the NYMEX Henry Hub and KCBOT Waha Hub futures markets rose from August through December 1995, but the increase was greater for the Henry Hub contract.** Futures prices at the Henry Hub doubled from $1.42 per million Btu on August 2 to $2.87 on December 27. In contrast, futures prices at Waha increased by only 51 percent, from $1.29 to $1.95 per million Btu. Besides differences in weather and storage levels, the lower prices for the Waha contract reflect the western market's access to relatively low-cost Canadian gas.

- **The Henry Hub futures prices were more volatile than the Waha Hub prices, but both contracts had greater volatility than most other commodity contracts.** Monthly annualized price volatility, which is a measure of the average variability in percentage changes in price between days,[7] reached a peak of 177 percent during December 1995 (Figure 2) for the NYMEX Henry Hub contract and ranged from 56 to 64 percent for the KCBOT contract between December and February. This large price volatility or risk reflects the price changes in the related spot markets and explains the importance to the natural gas industry of financial instruments for bringing price risk under control.

- **The Henry Hub contract reached an all-time peak of almost 100,000 contracts traded during December 1995, reflecting the large volumes of gas subject to price risk**. Futures trading and outstanding futures contracts are often highest when market deliveries are at their highest levels, because the amount of commodity at risk is greatest. Gas delivery levels during January are usually 75 percent greater than levels during the summer months and greater than levels in any other month. In fact, monthly deliveries of natural gas for the 1995-96 heating season reached a peak of 2.4 trillion cubic feet in January 1996. Trading for the January 1996 contract closed on December 21, 1995.

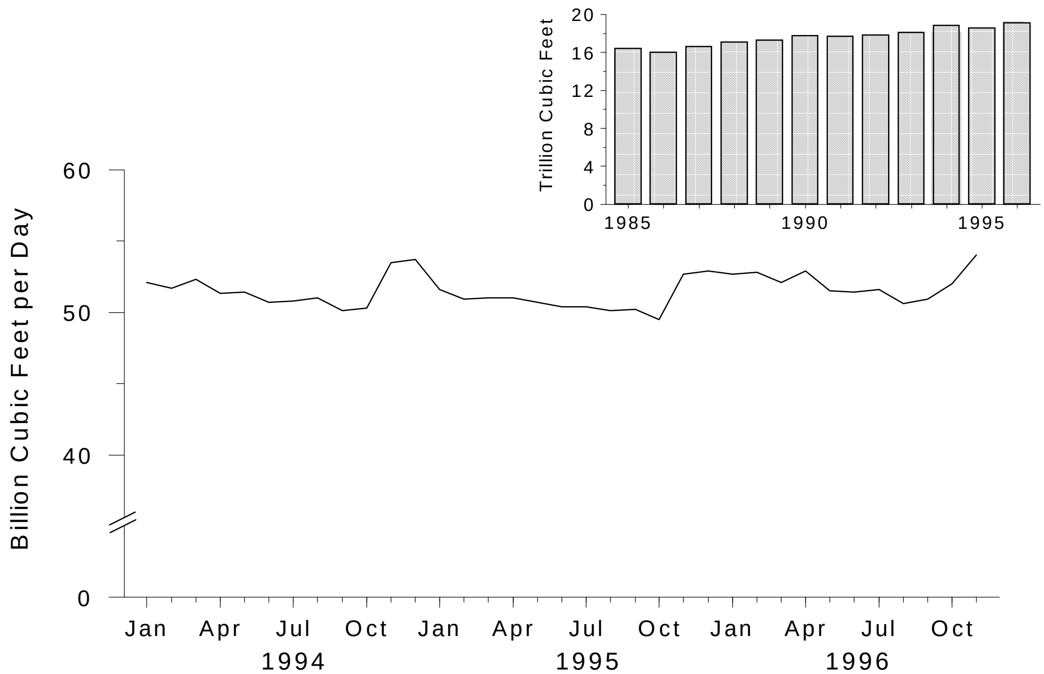
- **The volume of trade in the KCBOT futures contract declined from November 1995 through March 1996.** Part of this decline was due to above-normal temperatures in much of the West and adequate storage levels. Moreover, the percentage of contracts taken to delivery was generally high, which reduced the volume of trade. Deliveries amounted to about 12 percent of the volume of trade in March 1996 and were above 2 percent in several other months. Comparable figures for the NYMEX contract were less than 0.3 percent.

- **High price volatility also contributed to substantial activity in the options markets during the 1995-96 heating season.** On the KCBOT market, 315 options contracts were traded in September 1995. Trade peaked at 806 contracts in February 1996 and in March was still above August and September levels. The NYMEX options market reached a peak of almost 20,000 contracts traded in December 1995, and levels in March 1996 were also higher than in September. Moreover, the number of NYMEX options contracts (open interest) is often more than 30 percent of the number of futures contracts, which is higher than in most other commodity markets.

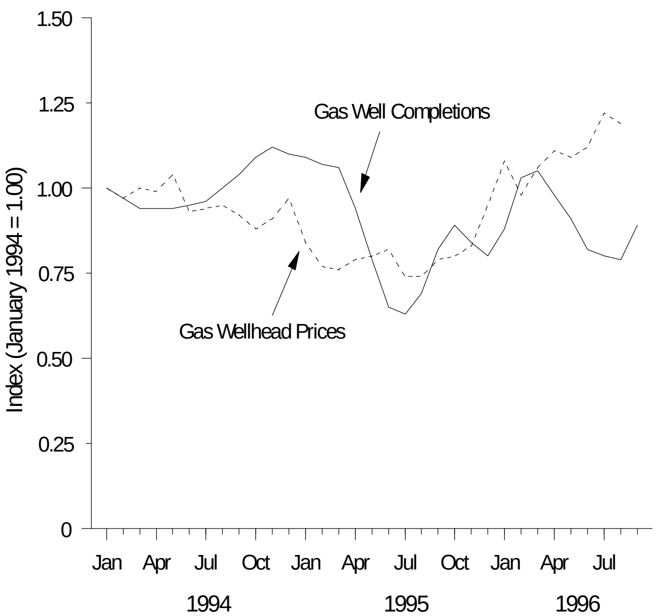
- **In 1995, the options markets grew at a faster pace than the futures markets.** Costs associated with taking a position in the options market are easier to estimate than are costs associated with the futures market. When the price of a futures contract exhibits increased volatility, the amount of down payment (margin) to maintain a position in the futures market also increases. In contrast, the cost associated with the options market is fixed at the time of purchase.[8] Also, unlike futures, options allow sellers to protect themselves from a fall in price while experiencing gains from price increases.

Figure 3. Natural Gas Supply Activities Continue at a Strong Pace

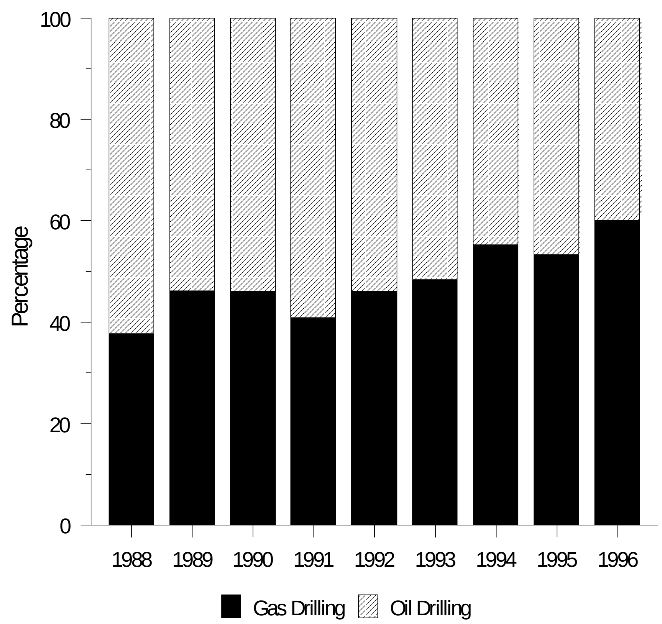
Natural gas production recovers in 1996



Natural gas well completions respond to higher prices in recent months



Rotary rig count shows industry preference for gas completions



Source: Energy Information Administration (EIA), Office of Oil and Gas. **Natural Gas Production and Wellhead Prices:** *Natural Gas Monthly* (November 1996). 1996 gas production is estimated from year-to-date data for 1994, 1995, and 1996. **Gas Completions:** Three-month moving average derived from data published in the *Monthly Energy Review* (October 1996). **Rigs:** *Monthly Energy Review* (October 1996). 1996 value is the average through September.

Data Trends: Gas Production

The response of gas producers to regulatory change has been a long-term increase in production even as wellhead prices have declined. The performance of the U.S. gas industry in 1995 reflected a continuation of that trend as production remained strong despite a sizeable decline in price. The success of domestic producers in recent years is in itself a significant factor that contributes to the prevailing low gas prices. This performance is expected to continue for at least the next few years with greater efficiency and continuing innovations in technology.

- **Natural gas production in 1996 is flowing at a rate expected to be the highest yearly volume since 1981.** Cumulative production in 1996 exceeds the comparable volumes in both 1994 and 1995. Dry marketed production fell from 18.8 trillion cubic feet (Tcf) in 1994 to 18.6 Tcf in 1995 (Figure 3). The production decline in 1995 is particularly striking given that productive capacity remained steady or increased, as indicated by the growth in proved reserves (see p. 9). Production during 1995 declined in the face of continued growth in imports and lesser volumes injected into storage compared with 1994. Increased deliveries to consumers and a greater need for replenishing storage have increased gas consumption in 1996, resulting in higher gas production while the average 1996 wellhead price through August has risen to $2.14 per thousand cubic feet (Mcf), which is 38 percent above the 1995 price of $1.55 per Mcf.

- **The largest production increases for 1995 occurred in Colorado and New Mexico, with incremental production gains of 64 and 69 billion cubic feet (Bcf), respectively**. These gains are due in part to the maturation or initiation of coalbed methane recovery projects and the expansion of transportation capacity to support marketing the larger volumes. Production actually declined in the offshore Gulf of Mexico despite continued development of several large, deep water projects. The declines are attributable to the relatively weak market for domestic gas production in 1995. Despite its 1995 performance, the Gulf of Mexico, especially in deep waters,[9] is expected to be a major growth area for U.S. natural gas production in the future.

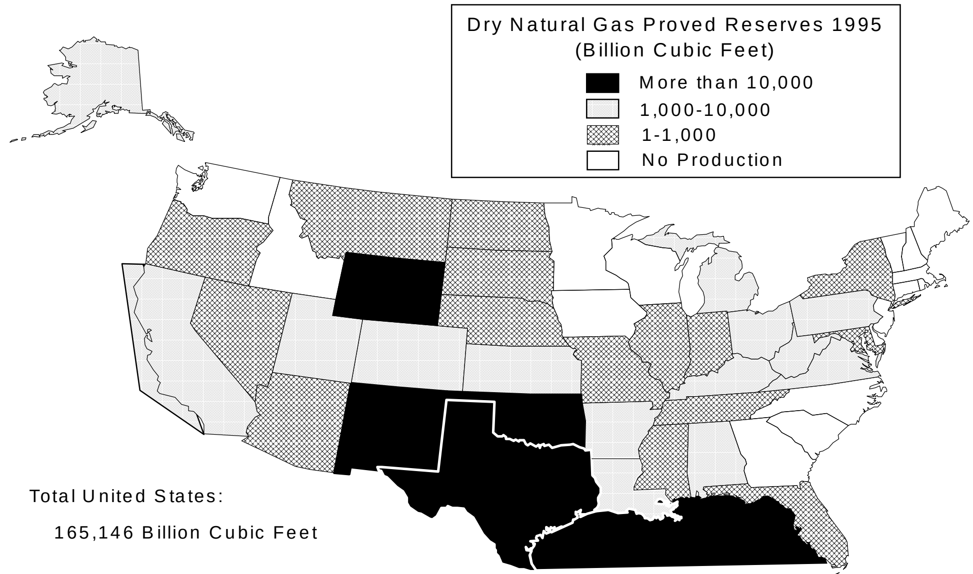
- **Natural gas well completions are up 9 percent from levels during the same period in 1995.** Gas well completions in the first 9 months of 1996 have responded to the rise in wellhead prices (Figure 3). Gas completions for 1995 were only 7,428, reflecting a drop of more than 1,500 from the prior year. This decline was driven by the fall in wellhead prices in 1995, which reached the lowest annual average (in constant dollars) since 1976. Exploratory gas well completions in 1995 increased for the third consecutive year. The fraction of gas well drilling directed toward exploration has risen in recent years to levels last seen in the first half of the 1980's. These trends are important to the industry's attempts to replace proved reserves, which is a key element in the Nation's productive capacity.

- **Recent technological research is expected to improve production performance from the reservoir.** Improved placement of the wells based on three-dimensional (3D) seismic technology has reduced the occurrence of costly dry holes and increased well performance in terms of both flow rates and ultimate recovery. Innovative thinking regarding 3D applications has led to "4D" reservoir monitoring, which uses 3D images from separate time periods to enhance understanding of reservoir flow characteristics and hence production performance. Additional work is directed at 4D applications in real time to improve production operations further.[10] Another technique with great promise is crosswell seismology, which can produce detailed 2D pictures of the area between two wells. The advantage of crosswell seismology lies in the significantly enhanced resolution of the data.[11] It offers operators the ability to improve production by better understanding the reservoir performance characteristics and structure. Recent design and methodology improvements are expected to lower costs in the future, which will contribute to further success of crosswell seismology.

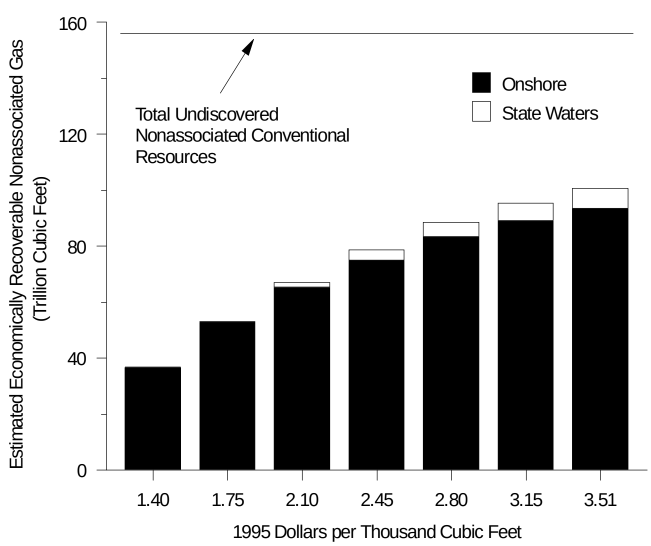
- **The share of rotary rigs in operation that are directed toward natural gas has been at record levels in recent years.** Rotary rigs utilized in gas well drilling in 1996 are 60 percent of total rigs (Figure 3). This record share is 58 percent more than the 38-percent share recorded in 1988, the first year in which rotary rigs were reported by well type. As rigs increasingly were directed toward gas targets, the mixture of successful well completions shifted until gas completions exceeded oil completions for the first time in 1993. This differential is striking because oil completions were more than double the number of gas completions as late as 1987. The preference for gas drilling is likely to continue in the near term, although the number of gas wells per rig declined slightly in 1994 and 1995.

Figure 4. Natural Gas Resources Are Heavily Centered Around the Gulf of Mexico

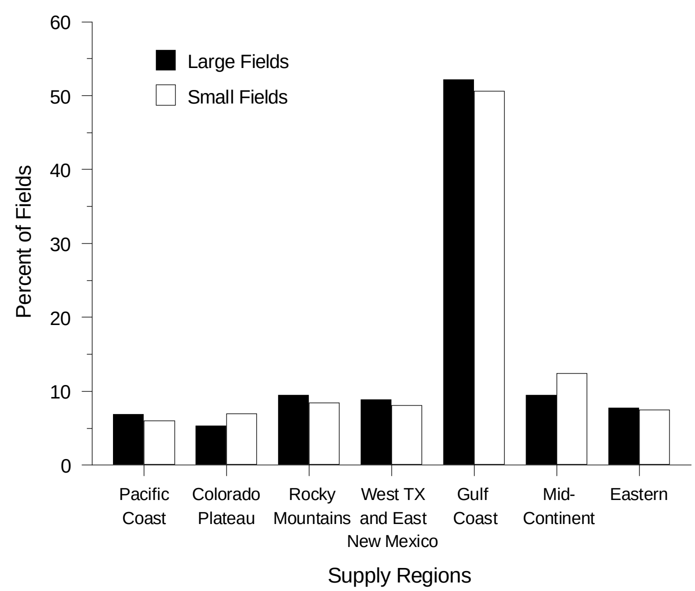
Texas, Louisiana, and the Offshore Gulf of Mexico are major supply sources



Larger volumes of gas resources are recoverable at higher unit costs



Remaining undiscovered gas fields are expected to be mainly in the Gulf Coast area



Notes: The lower left graph shows the marginal unit costs associated with recovery of the entire estimated resource volume. Thus, it is a cumulative figure that includes volumes recoverable with unit costs up to and including the stated value. The unit costs do not incorporate the dynamics of discovery, development, and production that are necessary to bring the gas to the market. This static, time-independent assessment of natural gas *stocks* does not show volumes that necessarily can be expected to *flow* to market at equivalent prices. The lower right graph shows gas field counts for the onshore lower 48 States and State waters. There are an estimated 2,812 undiscovered large gas fields (at least 1 million barrels of oil equivalent) and 35,427 small gas fields as of January 1, 1994. See Appendix A for map of supply regions.

Sources: Energy Information Administration (EIA), Office of Oil and Gas. **Proved Reserves:** derived from EIA, *Advanced Summary U.S. Crude Oil, Natural Gas, and Natural Gas Liquids Reserves: 1995 Annual Report* (October 1996). **Recoverable Resources and Remaining Undiscovered Fields:** derived from U.S. Geological Survey, "Economics and Undiscovered Conventional Oil and Gas Accumulations in the 1995 National Assessment of U.S. Oil and Gas Resources: Conterminous United States," Open-File Report 95-75H (1996).

Data Trends: Reserves and Resources

Natural gas proved reserves, from which production flows to market, are an important indicator of future gas production potential.[12] Proved reserves are replenished from the natural gas resources that exist as unproven volumes in already known fields or in currently undiscovered fields. Estimates of undiscovered recoverable gas resources are uncertain and continue to be the object of considerable study because of their importance to any future energy outlook.[13]

- **Dry natural gas proved reserves increased by 1.3 trillion cubic feet (Tcf) in 1995—the first consecutive increase in year-end reserves in 28 years.** Proved reserves of dry natural gas in the United States as of December 31, 1995, were 165.1 Tcf,[14] up 2.7 Tcf from the total in 1993. A major share of gas proved reserves are located in the Gulf Coast area, with Texas, Louisiana, Mississippi, Alabama, and the Federal offshore containing 79.3 Tcf, more than half the proved reserves for the lower 48 States (Figure 4). Other key States, with at least 7 Tcf or more, include the traditional major producing States of New Mexico, Oklahoma, Kansas, and Colorado. A State of growing significance is Wyoming with 12.2 Tcf in proved reserves, which ranks it fourth among the onshore lower 48 States.

- **Overall, reserve additions of 19.3 Tcf were sufficient to replace 107 percent of production.** The net increase in proved reserves for the lower 48 States measured 1.5 Tcf, however, this gain was partially offset by a 0.2 Tcf decline for Alaska. Total discoveries[15] of 11.0 Tcf were down from the 1994 quantity but were still 14 percent higher than the prior 10-year average. Wyoming had the largest gain in reserves of any State or region, with an increase of 1.3 Tcf, a 12-percent increase over the 1994 level. Wyoming includes reserves in conventional formations, tight gas formations, and coalbed methane deposits. Important contributions to proved reserves were from large gas accumulations discovered in deep water areas in the Gulf of Mexico, as well as other discoveries in onshore areas of Texas and Colorado. Recovery from coalbed methane deposits, located principally in New Mexico, Colorado, Alabama, and Virginia, has grown sharply in recent years. Coalbed methane production increased again in 1995, more than offsetting the slight decline in 1994. Coalbed methane reserves comprise over 6 percent of 1995 gas reserves and 5 percent of gas production.

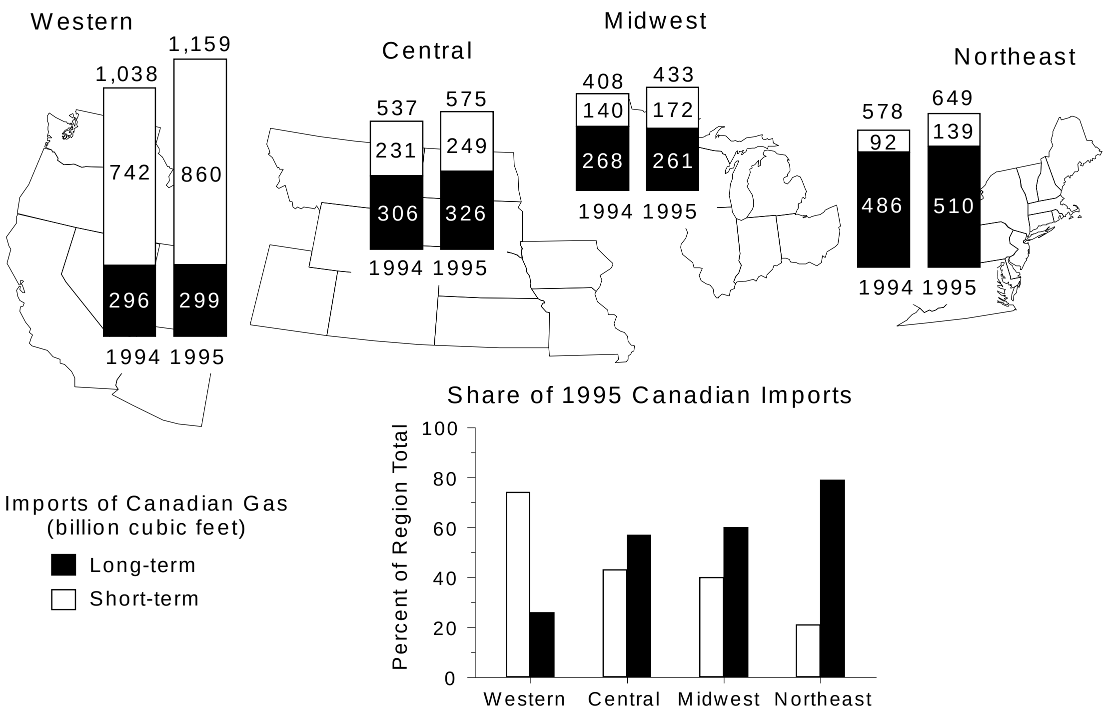
- **More than half the estimated nonassociated natural gas resources are expected to be producible at up to $2.10 per thousand cubic feet.** Undiscovered technically recoverable conventional natural gas resources in the onshore lower 48 States are estimated at 139.5 Tcf for nonassociated gas and 31.4 Tcf for associated gas.[16] State water regions off the lower 48 States are expected to contain 16.4 Tcf of nonassociated gas and 3.1 Tcf of associated gas.[17] Not all technically recoverable resources, however, are likely to be economic to recover. The U.S. Geological Survey (USGS) has developed estimates of economically recoverable oil and gas resources. In nonassociated gas accumulations with unit costs of discovery, development, and production up to $2.45 per thousand cubic feet,[18] there are an estimated 75 Tcf in the onshore States and 4 Tcf in State waters (Figure 4).

- **Roughly 94 percent of expected remaining undiscovered oil and gas fields in the lower 48 States, including State waters, are small fields with conventionally recoverable volumes of less than 1 million barrels of oil or 6 billion cubic feet of gas.** Remaining undiscovered oil and gas fields are estimated at almost 90,000, with about 5,500 large (at least 1 million barrels of oil equivalent) and 84,000 small fields. The relatively high proportion of small fields has important implications for future gas recovery. These fields present technological challenges in both discovery and recovery. Further, as the number of remaining large fields in a region declines, there is a lower expected return for all remaining prospects, regardless of size. Eventually, the economic attractiveness of exploring for conventional deposits is directly affected because the remaining, smaller targets may not offer sufficient returns to offset exploration costs including dry holes. Most of the gas is estimated to occur as nonassociated gas, with roughly half the large and small fields located in the Gulf Coast region (Figure 4).[19]

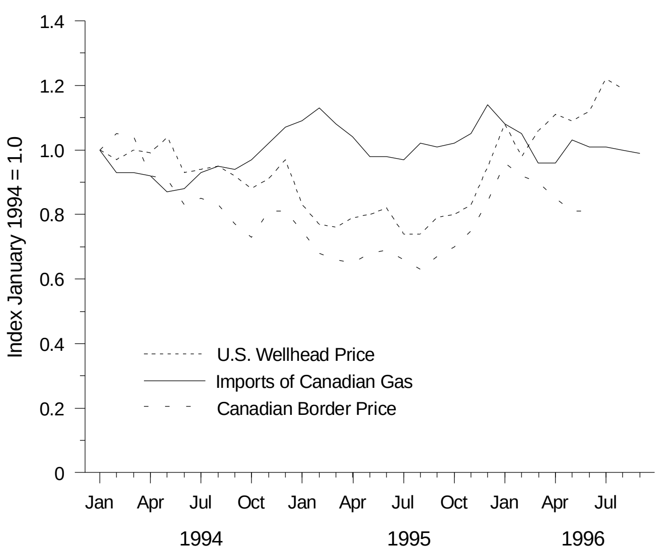
- **The Minerals Management Service (MMS) estimates remaining technically recoverable gas resources in the Federal Outer Continental Shelf (OCS) at 268 Tcf.** The new MMS estimates reflect more recent geophysical, geological, technological, and economic data and the impact of an enhanced methodology.[20] This analysis shows significantly greater volumes for the OCS regions off the Pacific Coast, the Atlantic Coast, and Alaska when compared with earlier estimates (1987). The expected gas recovery volume from the Gulf of Mexico OCS reflects more optimism even though the new estimate of 95.7 Tcf is 7.6 Tcf less than the figure published earlier, because the reduction is less than the 27 Tcf that was converted from unproven resources to proved reserves subsequent to the prior assessment.

Figure 5. Canadian Imports Dominate U.S. International Gas Trade

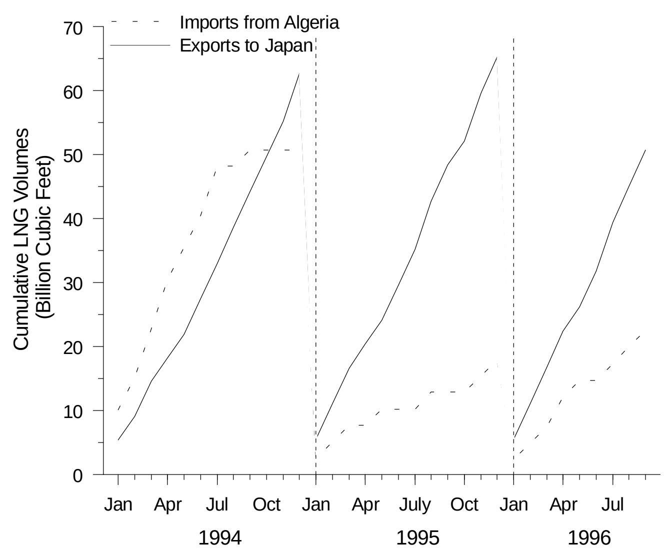
U.S. imports of Canadian gas occur increasingly under short-term contracts



Canadian gas prices recover somewhat, then begin to slump again



Lower LNG imports reflect Algeria's renovation of liquefaction plants



LNG = Liquefied natural gas.

Notes: Short-term imports are those made under purchase arrangements of 2 years' or less duration; long-term imports are for longer than 2 years. Regional import volumes are the sums of volumes imported into each region through the border points in the region. The index of imports of Canadian gas was constructed using daily average volumes for the months shown. 1996 data are preliminary.

Sources: Energy Information Administration (EIA), Office of Oil and Gas. **Long-term and Short-term Canadian Gas Imports:** derived from import and export data from U.S. Department of Energy, Office of Fossil Energy. **Indices of U.S. Average Wellhead Prices, Canadian Gas Import Volumes and Border Prices, and Cumulative LNG Import and Export Volumes:** derived from *Natural Gas Monthly* (November 1996).

Data Trends: International Trade

Total imports of natural gas continued their steady climb of the past 9 years, increasing 8 percent to 2.8 trillion cubic feet (Tcf) in 1995.[21] Liquefied natural gas (LNG) exports remain steady, while LNG imports are expected to increase to levels of a decade ago. Some major developments include:

- **Pipeline imports from Canada continued to dominate external sources of U.S. supply, accounting for 99 percent of 1995 total imports.** Imports of Canadian gas increased by 10 percent in 1995, reaching 2.8 Tcf. The share of total U.S. consumption provided by imported Canadian gas increased for the ninth year in a row, to 13 percent.[22] The average border price for Canadian gas declined for most of the past 2 years, although it recovered somewhat in the fourth quarter of 1995, following the trend in U.S. wellhead prices (Figure 5). The annual average price for Canadian gas at the border decreased markedly between 1994 and 1995, dropping 20 percent to $1.48 per thousand cubic feet (Mcf).

- **Short-term imports accounted for 50.4 percent of total 1995 imports from Canada, exceeding long-term imports for the first time.** The trend to short-term imports reflects a growing preference for more market-responsive arrangements. Short-term imports reached 1.4 Tcf in 1995, accounting for 85 percent of the increase over 1994 imports from Canada. The average border price was $1.18 per Mcf for short-term imports and $1.79 per Mcf for long-term imports.[23] Moving along the U.S.-Canadian border from west to east, the relative proportion of short- and long-term imports changes from predominantly short term in the Western Region to predominantly long term in the Northeast (Figure 5).[24]

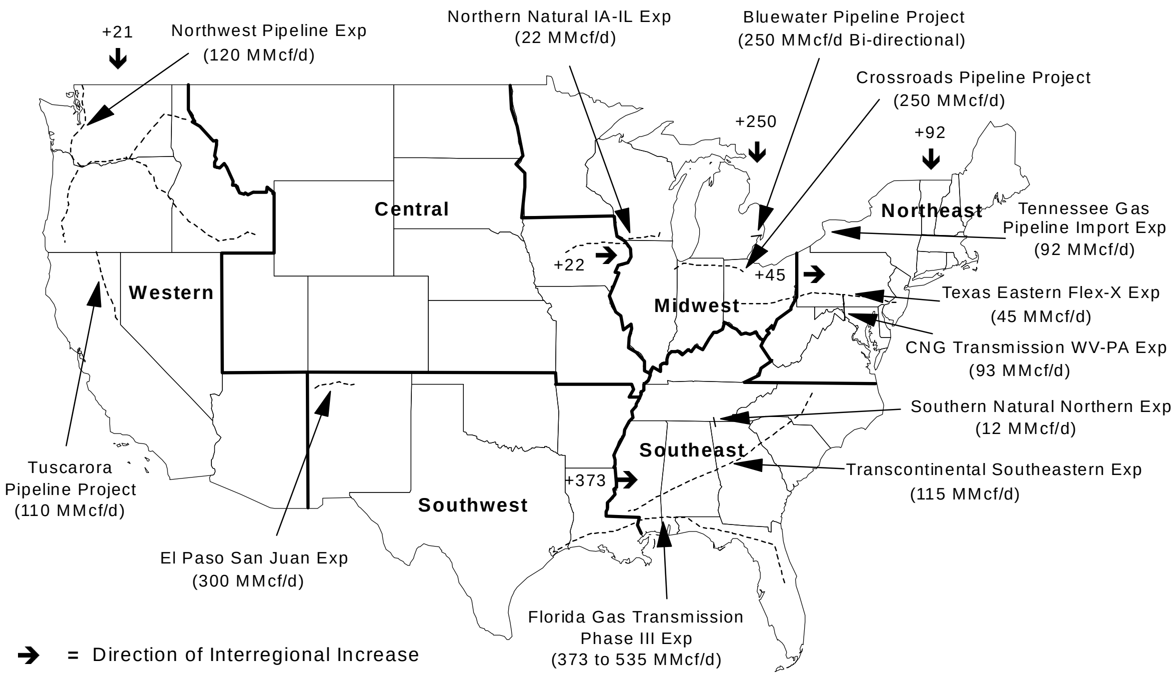
- **The Western Region continues to receive the largest share of Canadian gas—41 percent of total 1995 imports from Canada.** Western Region imports, at 1,159 billion cubic feet (Bcf), were nearly double the 649 Bcf imported into the Northeast, the next most highly served region. The Western Region had the largest share of the 1995 increase in imports of Canadian gas, receiving 120 Bcf, or 47 percent of the increase. At 26 Bcf, the Midwest had the smallest share, 10 percent.

- **The growth of imports from Canada likely will be stunted by the lack of available pipeline capacity to move gas into the United States.** Indeed, preliminary data for the first 9 months of 1996 show gas imports from Canada down about 2 percent from the year-earlier period. Capacity utilization on pipelines serving all export and import points averaged 87 percent in 1995,[25] and it was highest during the winter months. Pipeline capacities at major border points are tighter still. Utilization rates range from 89 percent at Sumas, Washington in the Western Region, to 100 percent at Waddington, New York on the Iroquois pipeline in the Northeast. Utilization rates at major export points into the Central and Midwest regions were 98 and 97 percent, respectively. Pipeline capacity constraints are hampering the ability of Canadian producers to move gas from the major producing areas in British Columbia and Alberta to U.S. Midwest and Northeast markets. These constraints have contributed to an excess of Canadian productive capacity and to the disparity in U.S. prices between eastern and western markets. A number of pipeline construction projects have been proposed to address this problem (Appendix G).[26]

- **Exports to Mexico have fallen recently, but might increase as a result of the recent explosion at a Mexican gas-processing plant.** By late 1995, Petroleos Mexicanos (PEMEX), the State-owned oil and gas production company, had reduced imports of U.S. gas by boosting its production from a decade-long average of 3.6 Bcf per day to about 4.2 Bcf per day.[27] Exports of U.S. gas to Mexico during the first 6 months of 1996 fell by 64 percent from the level for the same period a year earlier. Conversely, U.S. imports of Mexican gas during the same period rose from 0.3 Bcf to 9.6 Bcf.[28] However, PEMEX's near-term production goal of 5 Bcf per day by the year 2000 suffered a major setback with the July 1996 explosion at a major gas-processing plant in southern Mexico, which destroyed almost 1.5 Bcf per day, or about 33 percent, of Mexico's gas-processing capacity.[29] While some of the capacity has since been restored, expectations are for Mexico to increase imports of U.S. gas to make up the continuing shortfall.

- **LNG imports from Algeria fell to a 7-year low of 18 Bcf in 1995, but are beginning to recover (Figure 5).[30]** LNG imports fell because Sonatrach, Algeria's State-owned oil and gas company, initiated a multi-year renovation project in 1994 to restore its liquefaction plants to their original capacities. Project completion is scheduled for 1997, but import volumes have increased in 1996, because renovation work to date has returned export capacity to pre-renovation levels. Also, the Maghreb-Europe pipeline, connecting Algerian gas fields to markets in Spain and Portugal, should be completed in October 1996. This should free up the LNG capacity that has been used to serve Spain, Sonatrach's second-largest LNG customer.

Figure 6. Interregional Pipeline Capacity Increased Only 1 Percent in 1995



But planned construction projects could increase interregional capacity 7 percent by 1999

Region	Entering the Region[a] (MMcf/d)							Within the Region[b] (MMcf/d)						
	Existing Capacity 1995	Scheduled Additions to Capacity[c]					Percent Change from 1995	Existing Capacity 1995	Scheduled Additions to Capacity					Percent Change from 1995
		1996	1997	1998	1999	Total			1996	1997	1998	1999	Total	
Western	10,080	0	0	0	0	0	0	26,088	0	12	0	0	12	0
Southwest	2,523	0	480	0	0	480	20	57,127	600	3,005	0	0	3,605	6
Central	12,676	169	0	1,437	0	1,606	13	37,405	388	1,509	4,274	0	6,171	16
Midwest	24,632	0	716	1,155	1,200	3,071	12	48,666	46	986	1,407	4,800	7,239	15
Northeast	12,159	25	112	178	400	715	6	45,837	75	1,046	2,404	1,250	4,775	9
Southeast	21,586	0	145	0	0	145	1	72,550	0	625	1,239	1,000	2,864	1
Total	**83,656**	**194**	**1,453**	**2,770**	**1,600**	**6,017**	**7**	**287,673**	**1,109**	**7,183**	**9,324**	**7,050**	**24,666**	**9**
Canada	2,409	200	0	0	0	200	9	NA	NA	NA	NA	NA	--	--
Mexico	889	0	322	300	500	1,122	120	NA	NA	NA	NA	NA	--	--

[a]Includes only the sum of capacity levels for the States and Canadian Provinces bounding the respective region.

[b]Represents the sum of the interstate pipeline capacity, or planned capacity, on a State-to-State basis as measured at individual State border crossing points. Does not include projects which are entirely within one State. Gulf of Mexico projects are considered within the Southwest or Southeast region.

[c]New capacity has been counted in only one region even though some projects may cross regional boundaries. In the case of a new line, the additional capacity has been included within the region in which it terminates; for an expansion project, it is included in the region where most of the expansion effort is focused.

Exp = Expansion. MMcf/d = Million cubic feet per day. NA = Not available.

Sources: **Capacity:** Energy Information Administration (EIA), EIAGIS-NG Geographic Information System, Natural Gas Pipeline State Border Capacity Database, as of August 1996. **Capacity Additions:** Federal Energy Regulatory Commission, Natural Gas Act Section 7(c) Filings, "Application for Certificate of Public Convenience and Necessity," and various natural gas industry news sources.

Data Trends: Natural Gas Pipeline Expansions

The limited number of major pipeline expansions during 1995 reflects, in part, the ample availability of pipeline capacity in most parts of the national network. Interregionally, overall pipeline capacity increased by only 803 million cubic feet (MMcf) per day, represented by six projects, a 1-percent increase over the 1994 level.[31] Interstate capacity[32] increased by a relatively low 3,008 MMcf per day with the completion of an additional eight projects (Figure 6).[33] The trend in new construction has been to refine and expand locally to attract and hold customers. Other important improvements during 1995 included projects that increased pipeline linkups at "hub" sites and enhanced deliverability at strategic points along a number of pipeline systems.

- **Three new interstate pipelines were placed in service in 1995:** the Tuscarora pipeline (110 MMcf per day) serving northern California and the Reno area of Nevada; the Crossroads pipeline (250 MMcf per day) serving northern Indiana and western Ohio; and the bidirectional Bluewater pipeline (250 MMcf per day) transporting gas between Michigan and Ontario, Canada.

- **Two interstate expansion projects were completed that serve the growing gas markets of the Southeast.** Completion of the Transco Southeast expansion (115 MMcf per day) offers increased deliverability to customers in North Carolina. Completion of Florida Gas Transmission's (FGT) current expansion brings additional supplies to Florida from the Texas/Louisiana area and, in particular, from the Mobile Bay offshore area. The 535 MMcf per day expansion increases FGT's capacity into Florida to 1,475 MMcf per day. FGT is now studying the market feasibility of further expanding the eastern portion of its system and may file for a Phase IV project sometime in 1996.

- **Several intrastate pipeline projects were completed to improve access to hubs and pipeline interconnections.** For example, the TECO pipeline linkup between its western and east Texas lines provides a direct connection to services at its Waha and Katy Interchange Hubs (see Chapter 3). TECO now can transport up to 300 MMcf per day between the two hubs, providing a much needed service to customers wanting to move Permian and eventually San Juan Basin supplies to eastern and Midwestern markets.

- **An existing capacity bottleneck in the San Juan Basin area was reduced somewhat in 1995 with the completion of El Paso's San Juan project** (300 MMcf per day). This expansion not only increases the amount of production that may now exit the area but also supports the future completion of expansions eastward toward the Waha and Permian Hub areas. Currently, productive capacity in the San Juan area exceeds pipeline capacity exiting the area.

- **During 1995 and early 1996, several pipeline companies reevaluated their market requirements and, as a result, either downsized, postponed, or canceled projects.** For example, the Mayflower project, designed to expand deliverability off the Iroquois system to Massachusetts, was canceled because of insufficient customer support. Downsized projects include revision of the Transcolorado pipeline project to construct only the southern leg (in New Mexico) in 1997 and postpone the remainder of the system until additional pipeline capacity is built in the area to move supplies to eastern markets.

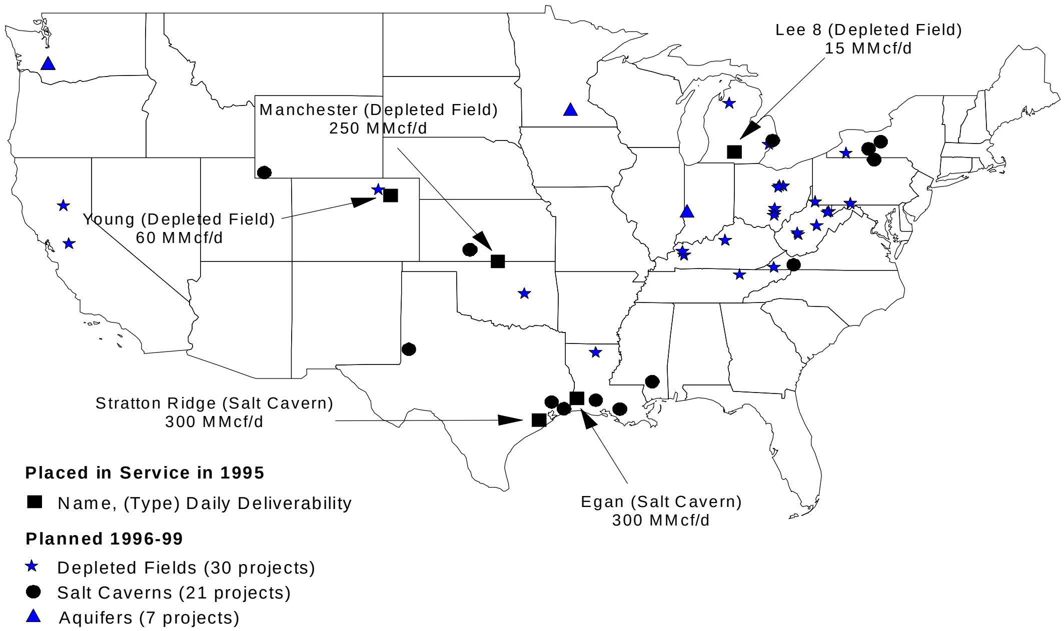
Proposed expansion projects continue to concentrate on removing some system bottlenecks and redirecting excess supplies to additional higher-value markets. The sustained cold weather in the Midwest and East during the 1995-96 heating season intensified interest in developing plans to move more western supplies eastward (see Appendix G). If all proposed projects were completed, interregional capacity would increase 7 percent by 1999 (Figure 6).

- **Projects to expand Canadian supply deliverability dominate current proposals**. Two projects in particular stand out. The first is the Maritimes & Northeast project that would, for the first time, move gas from Nova Scotia to the U.S. Northeast (400 MMcf per day). The second is the Alliance project that would expand deliverability (proposed 1,200 MMcf per day) from the supply-rich fields in British Columbia to the Midwest Region (Illinois).

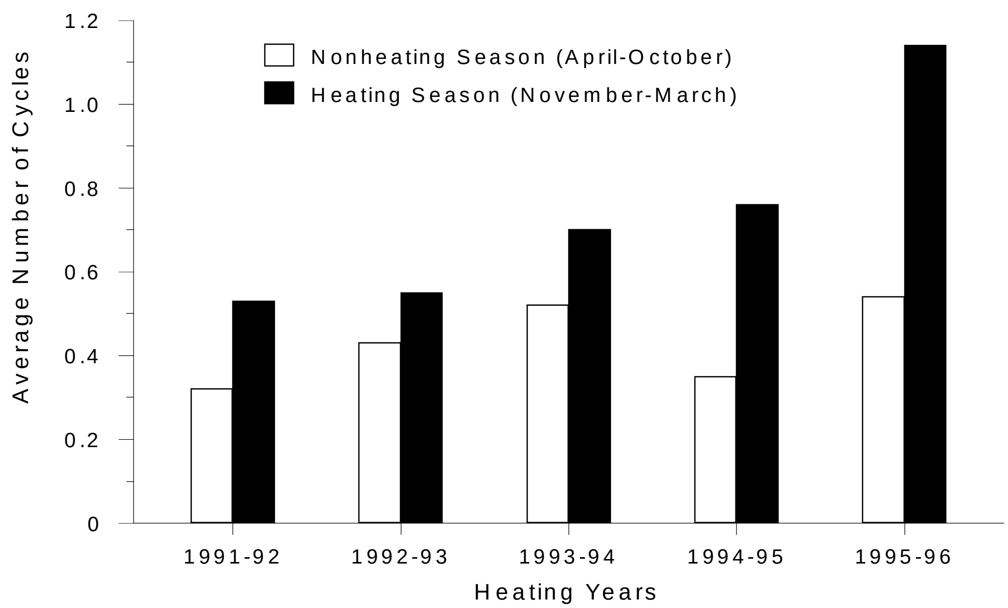
- **Several additional proposals address the issue of increasing capacity from the Rocky Mountain and San Juan Basin (southern Colorado/northern New Mexico) areas** and moving greater volumes eastward to the Midwest and Northeast regions. Among these are expansion of the Trailblazer system out of Wyoming and northern Colorado by 105 MMcf per day with a link to an expansion of Natural Gas Pipeline Company of America's Amarillo line toward the Midwest market. In addition, Transwestern Pipeline Company has filed for a 170 MMcf per day expansion and flow redirection on its line eastward from the San Juan Basin area. El Paso Natural Gas Company has also filed to expand its deliverability from the San Juan Basin to the eastern portion of its system and the strategic Waha area of West Texas by 180 MMcf per day.

Figure 7. High-Deliverability Storage Grew in Capacity and Usage in 1995

New salt cavern storage represented 65 percent of deliverability added in 1995



Salt cavern cycling during the heating season increased from 0.53 in 1991-92 to 1.14 in 1995-96



MMcf/d = Million cubic feet per day.

Notes: Mapped symbols represent sites. One site may have several projects (phases) associated with it. A heating year is from April of one year through March of the next year; for example, heating year 1991-92 is April 1991 through March 1992.

Sources: **Storage Sites:** Energy Information Administration (EIA), EIAGIS-NG Geographic Information System, Planned Underground Storage Database, as of July 1996; **Salt Cavern Cycles:** Form EIA-191, "Underground Gas Storage Report."

Data Trends: Underground Natural Gas Storage Developments

Entering the 1995–96 heating season (November 1 through March 31), underground natural gas storage deliverability in the United States was 2 percent greater than at the same time the previous year (see Appendix F). Some of the additional capability represented startups of high-deliverability (salt cavern) storage associated with expanding market center operations (see Chapter 3). Its availability during the extreme cold spells in January and February 1996 was probably a key factor in meeting increased demands during the period.

Working gas levels at the end of March 1996 were very low, 755 billion cubic feet.[34] As a consequence, storage refill activity through September 1996 was 20 percent higher than during the same period in 1995.[35] Nevertheless, the Energy Information Administration estimates that by the start of the 1996–97 heating season, working gas levels were about 2.8 trillion cubic feet, 7 percent lower than the previous year. This total, however, appears sufficient to meet anticipated needs, based on the amount of net withdrawals required to meet demand during the past three heating seasons—2 Tcf in 1995–96, 1.8 Tcf in 1994–95, and 2.3 Tcf in 1993–94.[36]

Several factors have contributed to the current status of the U.S. natural gas storage industry:

- **Storage has become a popular commodity in today's market.** It is offered by many market center operators and marketers as a multipurpose resource, such as to support short-term gas loans, gas balancing, and peaking services. Of the 39 market center operations in the United States and Canada, 26 offer storage as a major service.

- **Two of the five underground storage sites brought in service in 1995 were high-deliverability sites (Figure 7).** In addition, expansions were completed at 4 of the 17 existing high-deliverability sites. Although the 2 new high-deliverability sites represented only 30 percent of the added working gas capacity, they accounted for 65 percent (600 million cubic feet per day) of new daily withdrawal capability. The significance of these additions is not merely the absolute volume, but rather that this type of storage may be quickly cycled—that is, its inventory may be fully depleted and refilled as rapidly as once a month, while conventional storage may be cycled only about once during the 5-month heating season.

- **The utilization of high-deliverability storage has changed significantly in recent years.** Before 1993, this type of storage was often used and marketed in the same manner as conventional storage. Operators leased storage capacity to customers who used it primarily as seasonal backup supply rather than as peaking or short-term swing supply. Since 1991, the average cycling at these sites during the heating season has increased from about 0.53 cycles to about 1.14 in the 1995–96 season (Figure 7). For those sites associated with market centers, the average number of cycles during the 1995–96 heating season was a significantly higher 1.45, reflecting the more intensive use of these facilities.

- **Drawdowns from base gas inventory at a number of storage sites** during the past heating season, particularly in the Northeast and Midwest, raised some concerns about the need to build new storage. The percentage of total base gas inventory withdrawn, 1.7 percent, was well above the 1.0 percent withdrawn during the very cold 1993-94 heating season. However, the volume withdrawn was only 72 billion cubic feet,[37] which amounts to only 2.7 percent of total gas withdrawals during the heating season.[38]

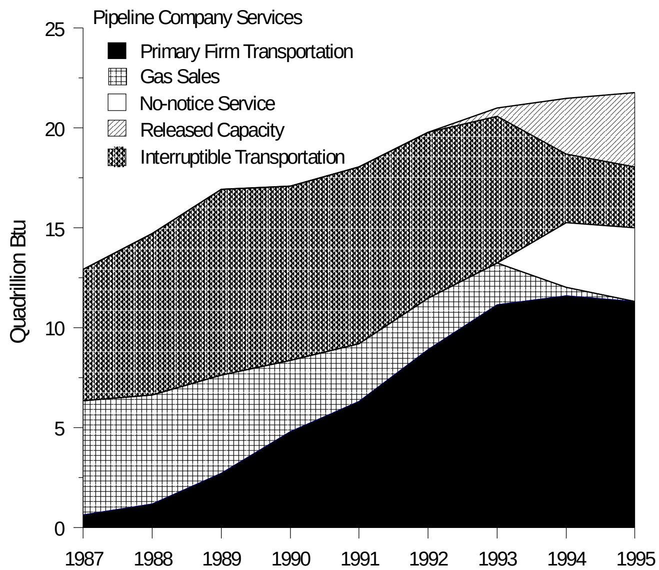
The success of underground storage operations during the past two heating seasons and the more efficient use of existing storage will probably affect plans for proposed storage projects. Most of the new proposals announced during the past 12 to 24 months have been expansions to existing sites. In addition, several projects have been postponed or redesigned in response to changed shipper needs, market demand, or market center efficiencies.

- **The current list of proposed projects (through July 1996) has dropped to its lowest level since the Energy Information Administration began tracking in 1993.**[39] Planned projects through 1999 currently total 58, about a third less than the number planned in 1994.[40] Proposed increases to daily deliverability would amount to 9,936 million cubic feet (MMcf), well below the 20,746 MMcf per day planned as recently as October 1994. This change reflects the completion of approximately 12 new sites and 14 expansion projects since then and plans for only 7 additional new proposals.[41] The majority of the planned increases in deliverability and working gas capacity is still in the form of salt cavern storage, but now most of these (14) are expansions to recently completed projects.

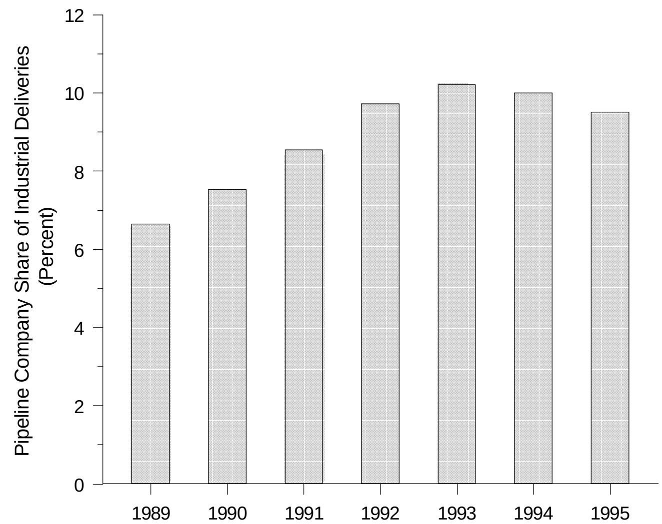
- **A significant increase in daily deliverability is planned to be put in place in the Northeast and Midwest regions** at a number of conventional (depleted field) storage sites owned by Columbia Gas Transmission Company. Columbia will be improving facilities at 13 underground storage sites and increasing daily deliverability by 326 MMcf by the end of 1998. Working gas capacity will essentially remain the same.

Figure 8. Service Selection and Costs Have Changed in the Natural Gas Transmission Market

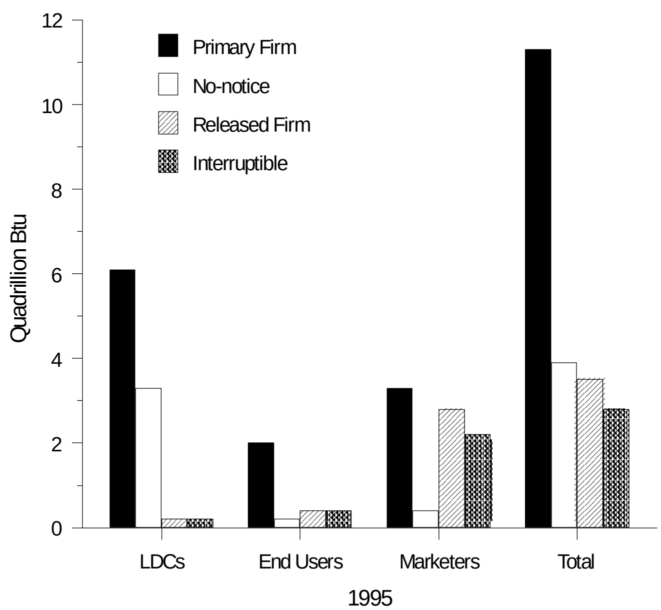
Choices of delivery services have changed



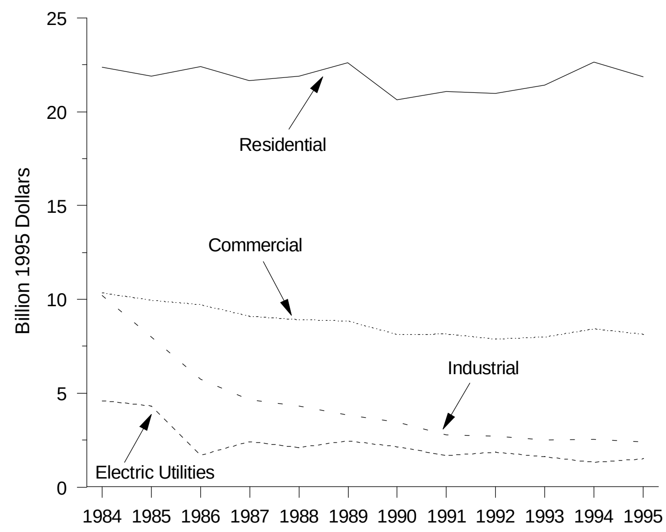
Interstate pipeline companies' share of the industrial market may be leveling off



Marketers' selection of transportation services is the most diversified



Annual natural gas transmission and distribution costs have declined for most end-use sectors



LDC = Local distribution company.

Notes: The commercial and industrial transmission and distribution costs reflect end-use prices for onsystem sales only. The onsystem share of industrial deliveries was 75 percent in 1984 and 24 percent in 1995. The onsystem share of commercial deliveries was 100 percent in 1984 and 77 percent in 1995. Values expressed in 1995 dollars based on chain-weighted gross domestic product (GDP) deflator from the U.S. Department of Commerce, Bureau of Economic Analysis.

Sources: **Deliveries:** Interstate Natural Gas Association of America (INGAA), *Gas Transportation Through 1995* (September 1996). **Pipeline Company Share:** Energy Information Administration (EIA), Office of Oil and Gas, derived from Form EIA-176, "Annual Report of Natural and Supplemental Gas Supply and Disposition." **Transmission and Distribution Costs:** EIA, Office of Oil and Gas, derived from: 1984-1986—*Natural Gas Annual 1988* (October 1989; 1987-1990—*Natural Gas Annual 1991* (October 1992); 1991-1995—*Natural Gas Annual 1995* (November 1996).

Data Trends: Service Selection and the Transportation Market

The interstate natural gas pipeline industry completed the shift to nonmerchant services in 1995, and a similar switch from sales to transportation service has gained momentum in retail markets. Annual transmission and distribution costs, which declined almost 3 percent in real terms between 1994 and 1995, also appear to have declined for most end-use sectors. One uncertainty for the industry is the future role of long-term transportation arrangements in consumers' service portfolios. The availability of alternatives to long-term, firm transportation services, such as market area storage, may lead to future reductions in capacity commitments and to the emergence of additional challenges for the industry in marketing capacity and the pricing of services.

- **In 1995, interstate pipeline company firm services (primary firm transportation, no-notice service, and released capacity) dominated gas deliveries, while pipeline company sales were virtually nonexistent[42] and interruptible transportation continued to decline** (**Figure 8**). Firm transportation services represented 86 percent of gas deliveries in 1995, up from 82 percent in 1994. Although the 1995 total gas volume delivered to market was about the same as its 1994 level, data show that use of released capacity and no-notice service increased.[43] Primary firm transportation service continued to represent just over 50 percent of deliveries to market in 1995. The decline in shippers' use of interruptible transportation that began in 1990 continued into 1995. Compared with 1994, interruptible transportation volumes fell by 11 percent in 1995, from 3.4 trillion cubic feet (Tcf) to 3.0 Tcf. Interruptible transportation represented 14 percent of total volumes delivered for market in 1995.

- **The interstate pipeline companies' expansion into the industrial retail market may be leveling off.** Interstate pipeline companies increased their share of deliveries to industrial customers from 6.6 percent in 1989 to 10.2 percent in 1993 (Figure 8). In 1994 and 1995, however, the share dropped slightly to 10.0 and 9.5, respectively. Nevertheless, deliveries per industrial customer increased from 1,087 million cubic feet in 1994 to 1,245 million cubic feet in 1995.

- **Marketers appear to select the most diversified portfolio of interstate pipeline company services, transporting about equal amounts using primary firm, released firm, and interruptible transportation (Figure 8).** Local distribution companies (LDCs) and end users, on the other hand, continue to use primary firm transportation as their principal means of transportation. As a result of their service selections, marketers accounted for 80 percent of all volumes transported under released capacity in 1995 (see Chapter 2). LDCs accounted for 54 and 85 percent of the primary firm and no-notice transportation volumes, respectively, in 1995.

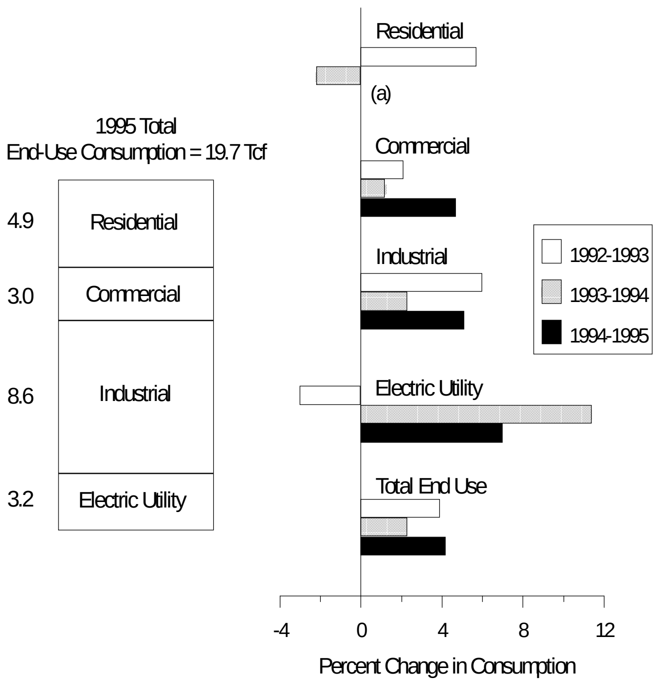
- **Companies that provide local delivery services (local companies)[44] have also witnessed a shift from sales to transportation service by their customers.** Deliveries to end users by local companies in 1995 increased by 3 percent over 1994 levels,[45] while transportation deliveries to end users increased by more than 5 percent to 8.1 Tcf. Concurrently, gas sales by local companies, which represent over half of their deliveries, increased by 1 percent to 9.9 Tcf in 1995. Transportation accounted for over 74 and 67 percent of deliveries by local companies to industrial and electric utility customers, respectively. This compared with 23 percent to commercial customers and negligible transportation to residential customers. Although sales dominated local company deliveries to residential customers, that situation may change as States accelerate their efforts to provide residential customers access to unbundled gas service (see Chapter 6).

- **Annual transmission and distribution costs, which exclude commodity costs, declined in real terms from \$35 billion in 1994 to \$34 billion in 1995.** These costs apply to all gas deliveries to the electric utility sector and onsystem sales to residential, industrial, and commercial customers.[46] Deliveries to these customers increased by more than 2 percent during the same period.[47] Compared with 1994, each customer group except electric utilities saw a decrease in total and per unit costs for transmission and distribution service (Figure 8).[48] The industrial sector had the largest decrease in transmission and distribution costs, 5 percent, while commercial and residential consumers each had decreases of 3 percent. Costs to electric utilities increased by 14 percent.

- **Market and regulatory changes are leading to expanded use of alternatives to long-term firm transportation** (such as market area storage and hub services) and a reduction in transportation capacity reserved on interstate pipeline companies. To date, the reduction or "turnback" of capacity has been limited to a few pipeline companies serving the Midwest and West. By the end of 2001, contracts covering 50 percent of capacity will have expired, providing shippers an opportunity to revise their capacity commitments. The extent and implications of a reduction in capacity reservations presents a number of cost allocation and operational challenges and is an emerging concern for the industry (see Chapter 2).

Figure 9. End-Use Consumption of Natural Gas Increases as Prices Fall

Electric utility consumption increased 7 percent in 1995

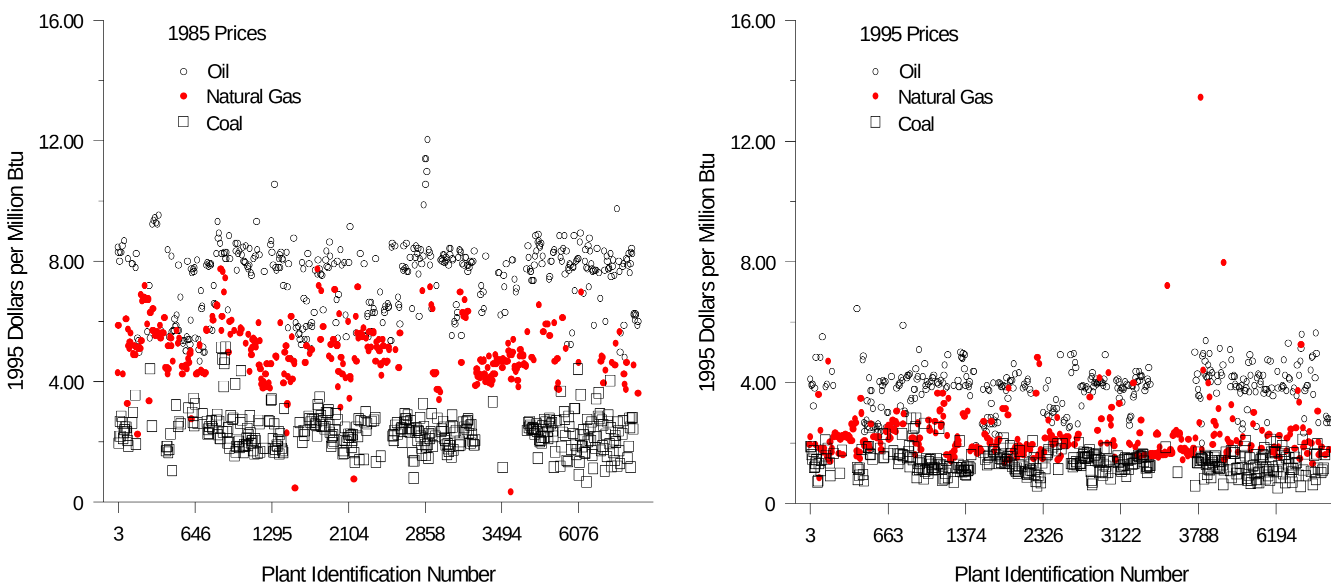


Real prices declined 8 to 14 percent in 1995

End-Use Prices
(Dollars per Thousand Cubic Feet)

Year	Residential	Onsystem Commercial	Onsystem Industrial	Electric Utility
	(nominal dollars)			
1993	6.16	5.22	3.07	2.61
1994	6.41	5.44	3.05	2.28
1995	6.06	5.05	2.71	2.02
	(real 1995 dollars)			
1993	6.46	5.47	3.22	2.74
1994	6.57	5.57	3.13	2.34
1995	6.06	5.05	2.71	2.02

Fuel prices to electric utilities have declined and converged during the past decade



[a]Residential consumption rose 0.04 percent from 1994 to 1995.
Tcf = Trillion cubic feet.
Source: Energy Information Administration. **Volumes and Prices by Sector:** *Natural Gas Annual 1995* (November 1996). **Prices by Plant Identification Number:** Office of Integrated Analysis and Forecasting, derived from Federal Energy Regulatory Commission Form 423, "Monthly Report of Cost and Quality of Fuels for Electric Plants."

Data Trends: End-Use Consumption and Prices

End-use consumption of natural gas in 1996 continues to move higher than 1995 levels, averaging 3 percent above 1995 consumption through November. There were strong increases in the residential and commercial sectors because of colder-than-normal weather in early 1996. In contrast, electric utility consumption dropped by 9 percent during the first 11 months of 1996 after posting strong growth the year before. The overall increase in consumption to date follows a 4-percent rise in end-use consumption from 1994 to 1995.[49] End-use consumption of natural gas increased in 1995 to 19.7 trillion cubic feet (Tcf), only 220 billion cubic feet short of the historical high recorded in 1972.[50] Demand was spurred by widespread economic growth during the year, resulting in consumption increases of 4 percent or more in the commercial, industrial, and electric utility sectors compared with 1994 (Figure 9). In nominal terms, average prices in all sectors fell from 5 to 11 percent between 1994 and 1995. Preliminary data for the first 11 months of 1996 show price increases in all sectors.

- **Residential and commercial consumption during the first 11 months of 1996 was 9 percent higher than in the same period of 1995** as cold weather increased demand for natural gas for space heating. Cumulative consumption from January through April 1996 exceeded the 1995 level by 13 and 15 percent, respectively, in the residential and commercial sectors. The weather was particularly cold in early spring. In March 1996, heating degree days were 14 percent colder than normal, and 27 percent colder than in March 1995. The estimated average price of natural gas from January through August 1996 is $6.16 per thousand cubic feet (Mcf) in the residential sector and $5.26 per Mcf in the commercial sector. For residential users, this is almost no change from that of the same period in 1995, while this is 3 percent higher for commercial users.

- **Industrial consumption of natural gas for the first 11 months of 1996 was 2 percent higher than in the same period of 1995, while consumption by electric utilities dropped by 9 percent.** Both sectors have seen large increases in the price of natural gas during 1996. For industrial users, the January-through-August average price is $3.30 per Mcf in 1996, 26 percent higher than in 1995. For electric utilities, the average price of natural gas for January through July (the latest month available) is $2.69 per Mcf in 1996, 35 percent higher than in 1995.

- **In 1995, commercial consumption rose 5 percent, while residential consumption barely increased over the 1994 level.** Residential consumption increased less than one-half percent to 4.9 Tcf in 1995, but was still slightly below the recent high in 1993. In November 1995, heating degree days were 13 percent colder than normal for the Nation, but the weather was generally warmer than normal during the other heating months of the year.[51] This dampened residential demand for gas even though new construction added to the housing stock. Sixty-six percent of new single-family homes constructed in 1995 were heated by gas.[52] Commercial consumption increased during the year in part because low interest rates contributed to economic growth. Both residential and onsystem[53] commercial prices fell in 1995, after rising by 4 percent in each sector in 1994. The average residential price was $6.06 per Mcf, which is 5 percent below the price in 1994. The average commercial price fell 7 percent during the same period, reaching $5.05 per Mcf for 1995.

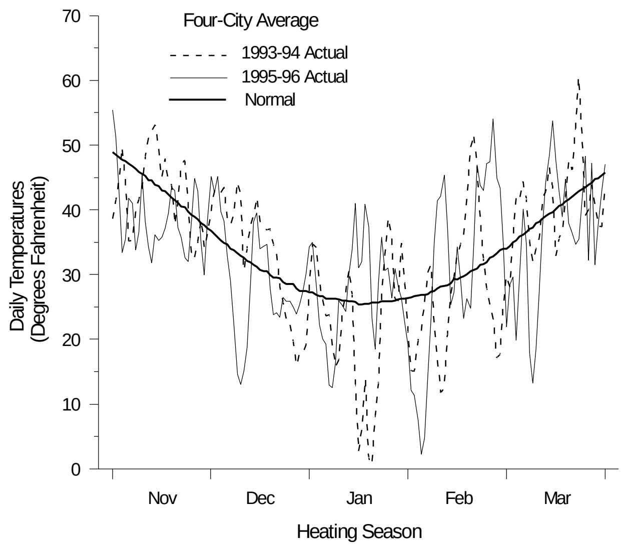
- **Industrial consumption of natural gas grew 5 percent in 1995, reaching 8.6 Tcf.** This continues the increase in consumption seen in this sector since the late 1980's and is only 109 billion cubic feet short of the historical high in 1973. Gas consumed by industrial cogenerators and nonutility generators (NUGs) is included in the data for this sector. In 1995, NUGs consumed 4.0 Tcf of natural gas—nearly double the amount in 1994.[54] The average price of natural gas to onsystem industrial users declined 11 percent in 1995 to $2.71 per Mcf.

- **Electric utility consumption of natural gas rose 7 percent in 1995 to 3.2 Tcf, while the average price in this sector fell by 11 percent.** This strong growth occurred without the prolonged outages at nuclear plants or low hydroelectric production that helped to spur the 11-percent increase in consumption during 1994. The average price of gas to electric utilities was $2.02 per Mcf in 1995, down $0.26 from the level in 1994.

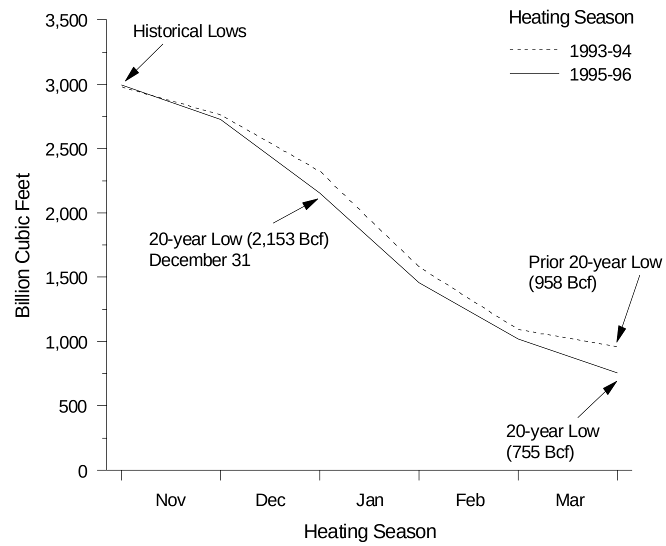
- **Competition to serve the electric utility market during the past decade has added to the price pressure on most major fuels used in this sector.** Data are available on the price of coal, natural gas, and oil used in more than 600 electric utility generation plants (Figure 9).[55] These data show a general stratification of prices by fuel in 1985, with the price (in 1995 dollars) of coal generally in the range of $1 to $4 per million Btu, gas in the $4 to $7 range, and oil in the $6 to $9 range. By 1995, the prices of all three fuels had declined, with coal still generally the cheapest. Oil and gas prices have fallen greatly, however, becoming more competitive with each other and with coal. By 1995, the prices paid by electric utilities for each of the three fuels were generally below $4 per million Btu.

Figure 10. How the Restructured Industry Responded to Recent Periods of Severe Winter Weather

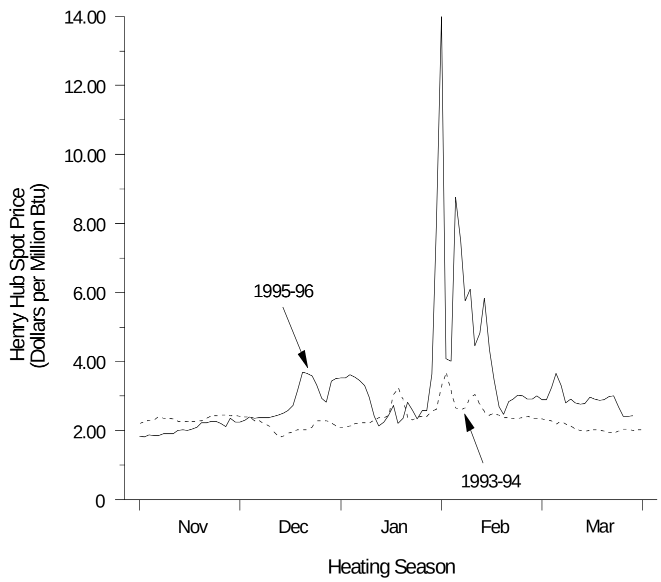
Both winters had extended periods of extremely cold weather

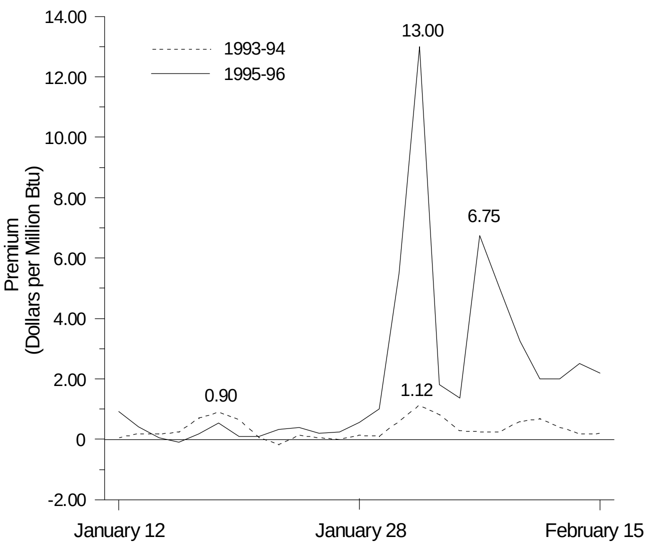


Working gas levels reached several historical lows



Natural gas price markets reacted differently during the two severe weather periods





Bcf = Billion cubic feet.

Notes: Temperatures are the average of temperatures for Chicago, Kansas City, New York, and Pittsburgh. The premium is the difference between the spot price and the New York Mercantile Exchange (NYMEX) nearby month futures price, both at the Henry Hub.

Sources: Energy Information Administration (EIA), Office of Oil and Gas. **Temperatures:** derived from National Oceanic and Atmospheric Administration, National Climatic Data Center. **Working Gas in Storage:** EIA, Form EIA-191, "Underground Gas Storage Report." **Premium:** derived from Spot Prices—Pasha Publications, Inc. *Gas Daily* and Futures Prices—Commodity Futures Trading Commission, Division of Economic Analysis.

Key Issues: Dealing with Cold Weather

The past decade has seen many changes in the natural gas industry. A good measure of whether the industry has retained its capability for reliable service after restructuring is to observe how it operates under stress. The highest and most variable demands for natural gas usually occur during the heating season (November through March) when periods of abnormally cold weather occur. Two recent periods of severe winter weather offer an opportunity to observe how various segments of the natural gas industry operated.

The industry's operational systems were tested during the winters of 1993–94 and 1995–96. Low storage levels in November 1995 and persistently cold weather kept working gas in storage at low levels throughout the 1995–96 heating season.[56] This led to great price uncertainty and to some of the highest gas prices ever recorded (Figure 10). Unusually cold temperatures in February 1996 extended into the producing regions, disrupting some supply activities for a day or two. Many pipeline companies reported record demand levels over the period.[57] In contrast, the 1993–94 heating season (the first season under Order 636) had only one sustained period of extremely low temperatures. Record cold weather east of the Mississippi in mid-January 1994 led to record levels of natural gas consumption. Several interstate pipelines and local distribution companies met or exceeded record weekly throughput.[58] Storage withdrawals for January 1994 were nearly 800 billion cubic feet (Bcf), the second-highest record for any month.[59] This level was not exceeded in 1995–96, but persistent cold weather and low storage throughout the season led to much larger price increases than in 1993–94.

- **Great demands were placed on natural gas storage resources.** At the beginning of November 1995, less than 3.0 trillion cubic feet (Tcf) of working gas was in storage. This was only the second time in 15 years that working gas levels were this low at the beginning of the heating season. By the end of December, working gas reached a 20-year low for the month of 2,153 Bcf (Figure 10). Preliminary data indicate that a record 2,691 Bcf of gas was withdrawn from storage during the 1995–96 heating season as cold weather continued throughout the period. Both natural gas production and imports from Canada were at expected levels, but without any significant increases from totals the previous winter. Thus, the management of storage was crucial as the industry successfully met the high, weather-driven demand of the season. Storage levels were also below 3.0 Tcf (2,978 Bcf) at the start of the 1993–94 heating season, but temperatures were near normal in November and December. The severe cold later in the 1993–94 season resulted in near record storage withdrawals of 792 Bcf in January and 567 Bcf in February.

- **Natural gas prices reacted to the abrupt and intense increases in demand during the cold periods of both heating seasons.** During the winter of 1995–96, prices skyrocketed on the spot market as buyers rushed to meet the peaking demands of their customers. At the Henry Hub in Louisiana, prices were above $15.00 per million Btu (MMBtu) on Friday, February 2, prior to the coldest weekend of the year (Figure 10). Reports in the trade press indicated that some industrial gas consumers paid more than $45.00 per MMBtu in Chicago in order to avoid pipeline imbalance penalties of over $60.00 per MMBtu.[60] The spot price for February 1996 averaged a record high of $4.41. The sharp price movements during this period indicate how the low storage levels and elevated demand created an atmosphere of price uncertainty. In 1994, the period of severe weather was of similar duration, 7 to 10 days, and also concentrated in the eastern part of the country. But the price movements at the Henry Hub were dramatically different. In January 1994, spot prices were around $2.25 per MMBtu before the cold spell, and by the fourth day of the severe cold had reached a high of $3.25. (Prices reached $3.70 on February 2, 1994, during a 2-day cold snap.) Another difference was that very few imbalance penalties were imposed on gas buyers in 1994, perhaps because it was the industry's first experience in dealing with cold weather while operating under Order 636.

- **The large difference between spot and futures prices showed how valuable it was to own gas during the stressful periods of both heating seasons.** The "premium," or the difference between the Henry Hub spot price for short-term (1- to 3-day) delivery and the futures price for deliveries the next month, becomes higher when temperatures are colder than normal. This indicates the value of having gas available for immediate delivery rather than at a future time.[61] In 1994, the premium reached $0.90 per MMBtu on January 19, but was less than $0.06 two days later. The highest premium of the season was $1.12 on February 2, falling to $0.28 on February 4. The more volatile spot prices in the 1995–96 heating season resulted in many more instances of extremely high premiums. The premium began to increase on January 30, when it was at $0.57 per MMBtu; by February 1, it was $5.50 as the cold weather arrived. It reached its highest level on February 2, a startling $13.00 per MMBtu. The premium was down to $1.36 in 2 days, but then spiked again at $6.75 per MMBtu and stayed well over $2.00 until the futures market for March delivery closed on February 23.

Table 1. The Top Natural Gas Marketers Will Change After Mergers

Top 10 Natural Gas Marketers in 1994

Marketing Company			
Rank	Name	Average Daily Sales (Bcf/d)	Parent Company
1	Amoco Canada Petroleum Co., Ltd	5.4	Amoco Corporation
2	Natural Gas Clearing House	3.7	BP Gas and NOVA Corporation
3	Associated Gas Services	3.6	Panhandle Eastern
4	Western Gas Marketing Ltd.	3.2	TransCanada PipeLines Limited
5	Enron Capital & Trade Resources Corp.	3.0	Enron Corporation
6	Chevron Natural Gas Services, Inc.	2.9	Chevron USA
7	Coastal Gas Marketing Co.	2.7	Coastal Corporation
7	Mobil Natural Gas, Inc.	2.7	Mobil Oil Corporation
9	Exxon Co., USA	2.1	Exxon Corporation
10	Texaco Natural Gas	2.0	Texaco Inc.

Estimated Sales After Mergers

New Marketer			
Company Name	Estimated Average Daily Sales[1] (Bcf/d)	Merging Marketers	Merger Status
Natural Gas Clearing House	10.0	Chevron Natural Gas Services, Inc. / Natural Gas Clearing House	Completed
PanEnergy	7.6	Mobil Natural Gas, Inc. / Associated Gas Services	Completed
To be announced	7.0	Coastal Gas Marketing Co. / West Coast Energy Services	Pending
To be announced	6.5	Tenneco Energy Resource / El Paso Energy Corporation	Pending
Coral Energy Resource	4.5	Shell Gas Trading / Tejas Gas Corporation	Completed

[1]Estimated average daily sales are based on company press announcements and are not the sum of pre-merger volumes reported for 1994.
Bcf/d = Billion cubic feet per day.
Note: Enron Capital and Trade Resources Corp. has not merged, but averaged an estimated 7.65 billion cubic feet per day in sales during 1995.
Sources: **1994:** Ben Schleisinger & Associates, *Directory of Natural Gas Marketing Service Companies, Ninth Edition* (April 1995). **Estimates:** Various industry news sources as of September 1996.

Key Issues: Mergers and Acquisitions in the Gas Industry

Restructuring and increased competition in the natural gas industry have created new opportunities for companies that in turn have resulted in numerous mergers and acquisitions. In a competitive industry, companies seek to increase market share and also diversify into profitable new lines of business. A company with high costs or burdensome debt might find itself vulnerable to acquisition, while other companies may merge to build on strengths that are considered unique to each company. Through mergers and acquisitions, companies attempt to add value by: (1) penetrating new markets and offering new services; (2) avoiding new investments by gaining access to new facilities; (3) cutting costs by eliminating duplicate services; (4) reducing overall management costs; and (5) establishing credibility and name recognition with customers.

- **Consolidation heats up among gas marketers.** In January 1996, Chevron Corporation and Natural Gas Clearing House announced a merger of their gas gathering, marketing, and processing businesses, which would create the Nation's largest marketer. The new corporation's sales would average more than 10 billion cubic feet per day, about 14 percent of North American natural gas consumption.[62] Other large marketer mergers are also either under negotiation or have recently been completed (see Appendix A). In such mergers, producers gain access to new markets and marketing expertise, while marketers gain access to relatively secure gas supplies. Also, marketers anticipate new gas marketing opportunities as State regulators begin to allow retail competition in local distribution.[63] Potential customers could increase from a few thousand large industrial and commercial customers to millions of residential users (see Chapter 6).

- **Recently completed and proposed mergers will reduce the number of major marketers and increase market share for the largest companies.** In 1994, Amoco was the leading gas marketer, averaging almost 5.4 billion cubic feet (Bcf) per day in sales, and Natural Gas Clearing House was second with sales of 3.7 Bcf per day (Table 1).[64] In 1997, the leading marketers will likely have double the sales of the largest marketing companies in 1994. The top 10 marketers in 1994 accounted for 31 Bcf in average daily sales, approximately 42 percent of U.S. daily consumption. After the planned mergers, this volume would represent sales of the four largest marketers.

- **Smaller marketers will still play a vital role despite these mega-mergers.** Market niches exist to aggregate small customer loads for larger marketers and also to aggregate gas production from small producers. For example, Tulsa-based Nimrod Natural Gas recently formed an alliance with Chevron to market Chevron's gas in the Chicago area. Despite these opportunities, smaller marketers will probably find themselves under increasing economic pressure as margins they earn from buying and selling gas become squeezed by the entry of large firms into the market.

- **More utilities combine forces to offer both gas and electric service.** Since January 1, 1995, a number of gas and electric utilities have announced plans to merge their operations (Appendix A). For example, Baltimore Gas and Electric (BG&E) plans to merge operations with Potomac Electric Power Corporation (PEPCO). BG&E provides gas and electric service to the city of Baltimore and 10 surrounding Maryland counties. PEPCO provides electric service to Washington, D.C. and two surrounding Maryland counties. The companies estimate that over 10 years they could save $1.3 billion from the elimination of duplicate services, the adoption of centralized purchasing, and reduction of management costs.[65]

- **Natural gas and electric utilities are merging to cut costs, expand their service territories, and to offer new multi-fuel services.** Many utilities believe that their knowledge of power and gas delivery systems places them in a unique position to compete with marketers for sales customers. They anticipate that as unbundling continues in retail gas and power markets, the best opportunities for profits will be in natural gas and electricity sales rather than in providing only transportation services.

- **Merging utilities are closely scrutinized by State public utility commissions.** In most States, utility mergers are subject to approval by the regulatory commissions. Specific criteria that regulators consider when deciding whether to approve a merger are: the effect on costs and rate levels, the proposed corporate structure, the reasonableness of the purchase price, and the existing competitive environment.

Table 2. Interest Grows in Alternative Transportation Rate Design

Alternative Transportation Rates for Interstate Pipeline Companies

Rate Design Method	Degree of Competition	Basis of Service Rates	Rate Limits	
			Upper	Lower
Traditional Cost of Service	Low	Estimated Annual Operating Expenses plus Return on Investment	Maximum Filed Tariff Rate	Minimum Filed Tariff Rate
Market-Based	High[1]	Customer Driven/ Rates for Competing Services	Market Determined	Variable Cost of Providing Service
Negotiated/Recourse				
Negotiated	Moderate[2]	Individually Negotiated with Each Customer	--[3]	--[3]
Recourse[4]	Low	Traditional Cost-of-Service Rate	Maximum Filed Tariff Rate	Minimum Filed Tariff Rate
Incentive-Based	--	Agreed upon Benchmarks[5]	--[6]	--

Companies that Have Filed for Negotiated/Recourse Transportation Rates

Company Name	FERC Docket No.	Date Filed	Status
NorAm Gas Transmission Company	RP96-200	April 1, 1996	Conditionally Accepted
Colorado Interstate Gas Company	RP96-190	April 15, 1996	Conditionally Accepted
Northern Natural Gas Company	RP96-272	June 7, 1996	Conditionally Accepted
Tennessee Gas Pipeline Company	RP96-312	July 16, 1996	Conditionally Accepted
Koch Gateway Pipeline Company	RP96-320	July 31, 1996	Conditionally Accepted
Florida Gas Transmission Company	RP96-330	August 2, 1996	Conditionally Accepted
National Fuel Gas Supply Corporation	RP96-331	August 2, 1996	Conditionally Accepted
Transcontinential Gas Pipe Line Corp	RP96-359	August 30, 1996	Conditionally Accepted
CNG Transmission Corporation	RP96-383	September 13, 1996	Pending
Columbia Gas Transmission Corporation	RP96-390	September 25, 1996	Pending
Columbia Gulf Transmission Company	RP96-389	September 25, 1996	Pending
East Tennessee Natural Gas Company	RP97-13	October 1, 1996	Pending
Midwestern Gas Transmission Company	RP97-14	October 1, 1996	Pending

[1]The Federal Energy Regulatory Commission will measure a pipeline company's market power using the Hirschmann-Herfindahl Index (HHI). While the HHI will indicate if a pipeline company has enough market power to suppress competition, the company's HHI level will not be the deciding factor for determining if market-based rates are appropriate. Market-based rate applications by companies with an HHI measurement greater than 0.18 will be more closely reviewed.

[2]Negotiated/Recourse rates may be an alternative when market-based rates are inappropriate.

[3]Negotiated rates may exceed maximum filed rates or be less than minimum filed rates.

[4]A pipeline company's recourse rates will be its effective cost-of-service rates.

[5]Benchmarks may include: average of rates charged by other companies in region, reduction in operating expenses, increased customer satisfaction.

[6] Although the 1992 Policy Statement on Incentive Regulation (61 FERC ¶ 61,168) required that rates under incentive regulation be no higher than they would have been under traditional cost-of-service regulation, FERC has eliminated this requirement from its current incentive rate evaluation criteria.

-- = Not applicable. FERC = Federal Energy Regulatory Commission.

Sources: **Alternative Transportation Rates:** Energy Information Administration, Office of Oil and Gas, derived from: Federal Energy Regulatory Commission orders and Commission Issuance Posting System. **Negotiated/Recourse Rate Filing:** Foster Associates, Inc., *Foster Natural Gas Report*, No. 2100 (October 3, 1996).

Key Issues: Transportation Regulatory Actions

The natural gas industry has witnessed major regulatory and legislative changes during the past several years. Some of the changes have allowed market forces to govern rate and service levels in areas of the industry where standard regulatory oversight was previously required. Recent regulatory actions have continued to expose more elements to market forces and have increased the options for interstate pipeline companies and shippers.

- **The Federal Energy Regulatory Commission (FERC) has established its evaluation criteria for market-based, incentive, and negotiated/recourse rates for transportation service.** FERC issued the policy statement on ratemaking alternatives in recognition that additional rate design flexibility may be needed in the restructured environment.[66] For instance, pipeline companies may need rate design flexibility to market excess capacity and recover costs associated with unsubscribed or "turned-back" capacity (see Chapter 2). Market circumstances are an important indicator of which type of alternative rate design method would be appropriate (Table 2). FERC will evaluate requests for alternative rates on a case-by-case basis.

  Pipeline companies appear to favor the negotiated/recourse method of the three alternatives to cost-of-service rates. As of October 1, 1996, 13 pipeline companies have filed for negotiated/recourse rates (Table 2). Most of the filings for negotiated/recourse rates have been conditionally accepted by FERC. The negotiated/recourse rate falls between market and cost-of-service rates in terms of how the rate is determined. A customer may "negotiate" a transportation rate with the pipeline company, or as a "recourse" choose to pay the effective cost-of-service rate. Although some issues still need to be resolved, it appears that the industry is embracing the concept of flexibility in rates.

- **Negotiated terms for pipeline company services may be another way of increasing flexibility in the transportation industry.** In addition to its policy statement on ratemaking alternatives, FERC has established a proceeding in which it will consider a proposal to allow pipeline companies to negotiate service terms and conditions. Negotiating terms and conditions may allow pipeline companies to tailor services to meet their customers' specific needs. Various sectors of the industry have asked FERC to ensure that pipeline companies do not enhance services to flexible customers at the expense of the remaining customers. Some generic benchmarks, with respect to pipeline company terms, may be required to keep a degree of standardization across the industry. In addition, an expedited complaint process may be needed so that affected customers can avoid excessive hardships.

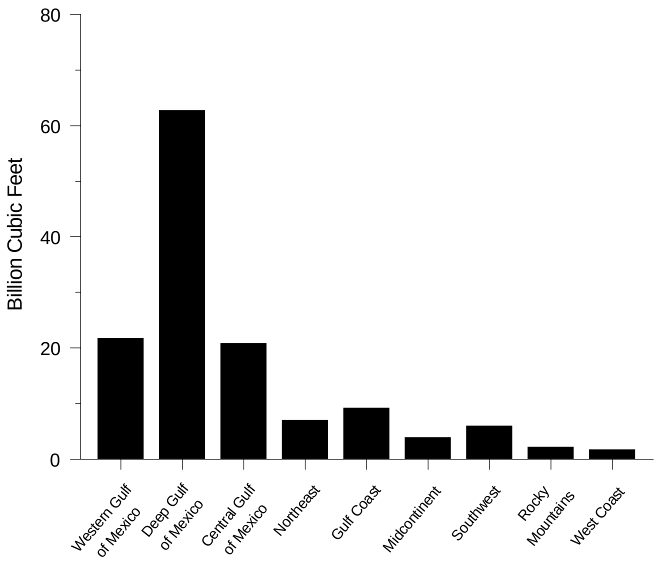
- **In addition to rate and tariff flexibility, FERC is providing pipeline companies flexibility with respect to access to markets.** In a January 31, 1996, order, FERC clarified that Order 636 does not prohibit interstate pipeline companies from obtaining capacity on other pipelines.[67] FERC stated that "to continue a prohibition on acquiring capacity on other pipelines may limit the flexibility that all industry segments may need to meet changing market demands." FERC will continue to review pipeline company requests on a case-by-case basis giving particular attention to four items: (1) pipeline company control of capacity and supply sources, (2) the rate impact on the acquiring pipeline company's customers, (3) preferential treatment of pipeline company marketing affiliates, and (4) integration of acquired capacity into open access systems.

  FERC perceives at least two benefits of pipeline companies holding capacity on other pipelines. First, it would allow the pipeline companies to provide shippers access to new supply and market areas. Second, it would reduce the administrative burden of shippers having to deal with several pipeline companies to secure the flow path they desire. Opponents of FERC's position believe that pipeline companies may use the capacity to exercise monopoly power while charging the cost of the capacity to core customers.

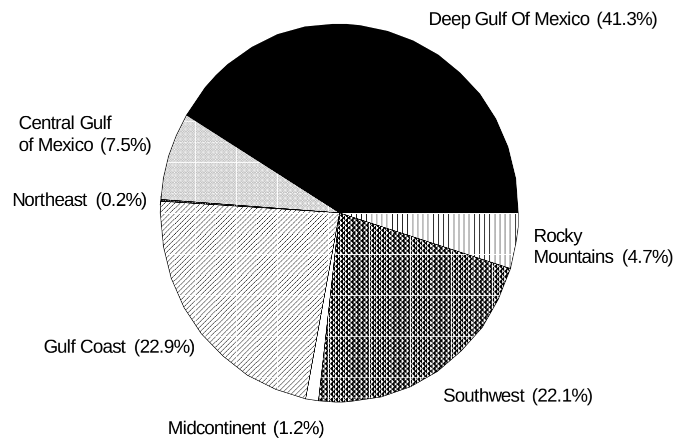
- **FERC has issued a Notice of Proposed Rulemaking to improve the operation of the capacity release mechanism and increase released capacity's value as a means of transporting gas.[68]** In the notice, FERC proposes to discontinue the current bidding requirements in an effort to end the uncertainty and delay some replacement shippers have experienced before they may use the released capacity.[69] FERC is also proposing to remove the price cap for released, interruptible, and short-term firm capacity when releasing shippers and pipeline companies can demonstrate that they are unable to exercise market power. In addition to making these services more comparable, removing the price cap will enable releasing shippers and pipeline companies to sell the capacity at market prices. Releasing shippers may also be able to recover more of their firm capacity costs, making the secondary market more attractive (see Chapter 2).

Figure 11. New Deep Water Fields Are Highly Productive

Average discovery size in deep waters dwarfs discoveries anywhere else in the lower 48

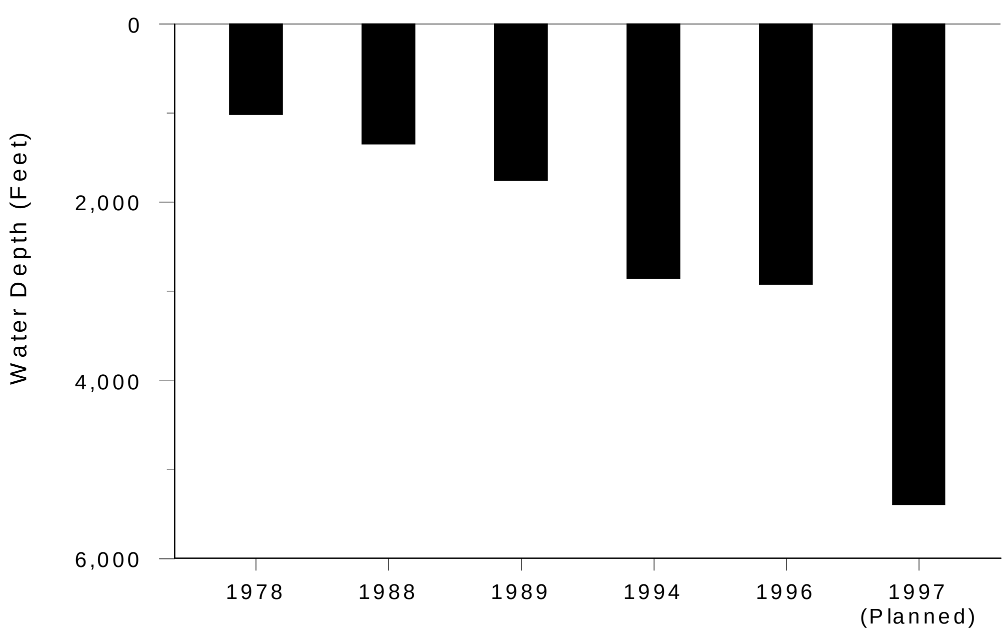


Deep water fields yield a major portion of . . . associated-dissolved gas in new fields



Total associated-dissolved gas for discoveries during 1990-1994 is 143 billion cubic feet.

Water depth records for producing projects have increased rapidly



Notes: Average discovery size (top left graph) does not include liquids in gas fields. New field discovery data for the top two figures are for discoveries made during 1990 through 1994.

Sources: Energy Information Administration (EIA), Office of Oil and Gas. **Average Discovery Size and Associated-Dissolved Gas in New Fields:** Form EIA-23, "Annual Survey of Domestic Oil and Gas Reserves." **Water Depth Records:** *Oil and Gas Journal* (November 13, 1995), p. 32.

Key Issues: Offshore Deep Water Development

Deep water regions[70] of the Gulf of Mexico are a prime growth area for domestic gas production. Productivity in these areas is the highest in the lower 48 States, but development had been inhibited because of relatively low prevailing gas prices and technical difficulties. The current outlook for deep water supplies from the Gulf of Mexico is encouraging because of technological improvements and the royalty relief program instituted in late 1995 by the Department of the Interior, both of which have lowered unit costs of exploration and development.

- **The average size of new field discoveries in the deep water Gulf of Mexico from 1990 through 1994 was 60 billion cubic feet, vastly exceeding that of any other area of the lower 48 States**. Deep water gas discoveries were three times the estimated recovery of shallow Gulf fields and at least six times the average field size discovered in any onshore region of the lower 48 States (Figure 11). The new oil fields in deep water contain substantial gas volumes. The associated-dissolved (AD) gas in these fields is estimated to be 59 billion cubic feet, or 41 percent of all AD gas in lower 48 new field discoveries from 1990 through 1994 (Figure 11). In contrast, the gas field discoveries in the deep Gulf during this period yielded only 3.5 percent of gas volumes discovered in lower 48 gas fields.

- **Technology is the driving factor that determines the development of deep water gas projects.** Deep water operations have benefited greatly from technology advances since the late 1980's such as three-dimensional (3D) seismic survey techniques and subsea completion technology. Use of 3D seismology is attractive for its capacity to limit costly dry holes and optimize well placement within the reservoir. A recent test demonstrated the use of satellites to transmit large volumes of information quickly for rapid analysis of 3D seismic data, which improves data collection by directing the seismic vessel to rework targets or move to another site. This enhancement in the 3D process offers the opportunity to save money and acquire better quality information.[71] More accurate and reliable data tend to encourage investment because uncertainty is reduced.

  Remotely operated subsea completions allow companies to transport gas from deep water fields back to producing platforms in shallower water that serve as centralized processing and gathering facilities. These "tie-back" arrangements enhance project economics by allowing producers to maximize utilization of existing on-site equipment and enhance economic returns by avoiding large expenditures for additional platforms and production equipment at the deep water locations. The importance of acquiring better technology for deep water activity is underscored by the alliances forming in the industry: Shell has a technology exchange agreement with Petroleo Brasileiro AS of Brazil, and Mobil is working with Norwegian companies on a new subsea completion system for water depths exceeding 8,000 feet.

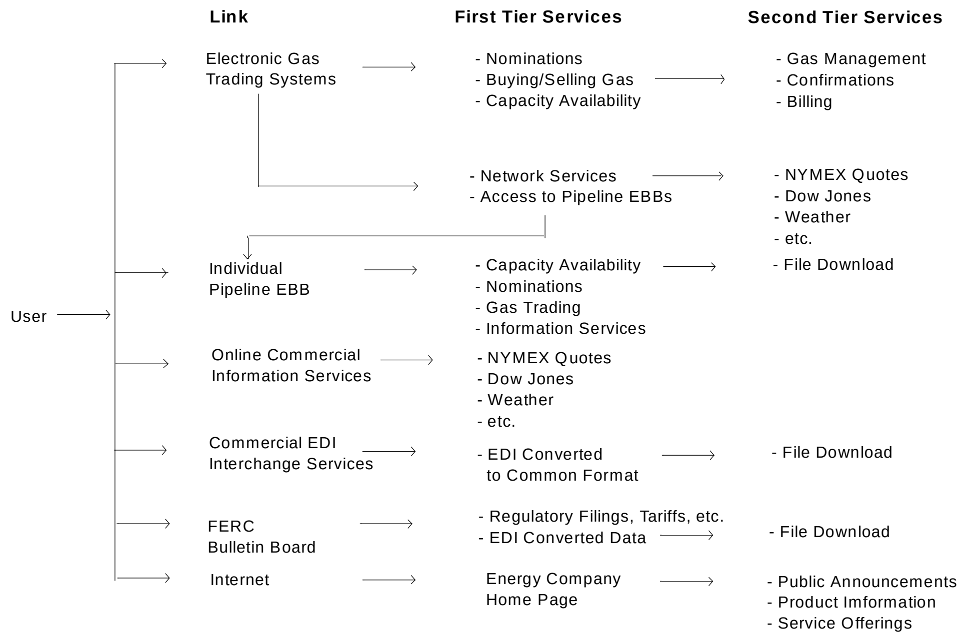
- **Deep water projects continue to come on line each year and add to the growing infrastructure as well as the record of success.** Deep water projects are extending into deeper and more distant locations in the Gulf of Mexico as evidenced by the evolving water depth records (Figure 11). In 1988, the Bullwinkle project came in at a depth of 1,350 feet, followed in 1989 by Joliet at 1,760 feet. These achievements were eclipsed with the Auger project in 1994 at 2,860 feet. The Mensa project, slated for initial production in 1997, will dwarf all of these with a water depth of 5,400 feet. This shift to ever greater depths is especially striking given the difficulties caused by increasing pressure and falling temperatures.

  Deep water projects also are being connected, or tied back, at increased distances to producing platforms in shallower water. The first instance of remote subsea production with a significant tie-back occurred with the Tahoe project in 1994 with a 12-mile tie-back. Shell's new Popeye project is a major step in the evolution of this approach. The Popeye field, in 2,000 feet of water, will be tied back over 24 miles to the Cougar platform in 350 feet of water, which will make it the longest tie-back from a subsea well. The Popeye project is serving as a testing ground for technology planned for the Mensa project, which is located in 5,400 feet of water with a planned 68-mile tie-back. The increasing reach of remote operations is an important aspect of the planning and design stage for development of new fields, which will increase the complexity of long-term project planning and investment decisionmaking.

- **The Minerals Management Service's (MMS) new royalty relief program contributed to a record-setting Gulf of Mexico lease sale.** The Deep Water Royalty Relief Act passed in late 1995 exempts deep water projects from Federal royalties on the first portion of production according to a sliding scale.[72] Royalties paid in the Federal offshore area typically are up to 17 percent of the gross value of production. The new royalty relief program apparently stimulated activity in the April 1996 lease sale for the Central Gulf of Mexico. The 1,381 bids received by MMS were a record count. Top bids, totaling more than $520.9 million, were received for 924 tracts.[73]

Figure 12. Electronic Communication Services Have Increased

Natural gas information is readily available



Gas trading is simplified by user-friendly programs

(Sample computer screen available only in hard copy format.)

EBB = Electronic bulletin board. NYMEX = New York Mercantile Exchange. EDI = Electronic data interchange. FERC = Federal Energy Regulatory Commission.

Sources: **Flow Chart:** Energy Information Administration (EIA), Office of Oil and Gas. **Computer Screen:** Altra Energy Technologies.

Key Issues: Importance of Electronic Information

The integration of computers and electronic communications with the transacting of business in the natural gas industry expanded rapidly during 1995 and early 1996. As recently as 1994, pipeline company electronic bulletin boards (EBBs) were extensively criticized for their complexity, slow speed, and operational problems. The current EBBs, however, are easier to use and more readily accessible. In addition, the electronic trading system concept for the industry has become much more developed with several full service systems that offer greater reliability and ease of use (Figure 12).

- **The new commercial electronic trading systems reflect the need for a single tool that provides access to market information during business transactions.** All of the major new or improved systems allow a customer remote access to their network via computer and, once linked, a number of optional services. These services include access to diverse information sources such as New York Mercantile Exchange (NYMEX) quotes, network E-Mail, other EBB operations, or alternatively to gas trading operations. Trading systems enable customers to buy and sell volumes and pipeline or storage capacity, as well as to conduct other trading activities, including billing, title transfers, and other administrative and accounting tasks (Figure 12).

- **Three new commercial electronic trading systems have been introduced since late 1994.** Currently, the most frequently used system is Altra Streamline, which was introduced in April 1995. It is used at eight natural gas market centers in the United States and three in Canada. Daily trading volumes at these centers range from 10 to 200 million cubic feet. Through its network, users can also access selected information (capacity release, operational flow orders, and notices of outages) from 45 pipeline company EBBs. Channel 4, the second most used system (four existing and two planned market centers), was introduced in 1994. Quick Trade, which began trading in early 1996, currently is operational at three market centers and 28 trading points on six pipeline systems. Several other commercial systems are available, although they are not as well known. A few natural gas market centers operate their own customized services.

- **The electronic data interchange (EDI) system for capacity release is being tested and improved.** Order 636 required each interstate pipeline company to maintain a certain minimum set of information for capacity release transactions. However, the 65 pipeline company EBBs have quite different content level and vary widely in ease of access and use. This variability was the driving force behind FERC's decision to implement standard electronic data formats in the EDI system for capacity release data. Even with the common EDI format, however, there still was inconsistency in how different pipeline companies provided the information. FERC has spent considerable effort to ensure that the EBB and EDI data are consistent. The problems of data discrepancies and differing formats also have resulted in action on the part of the industry to develop standards.

- **The Gas Industry Standards Board (GISB), a voluntary organization that comprises all segments of the natural gas industry, has been working to develop standards for electronic business transactions.** In March 1996, 248 business standards were proposed, covering nomination, confirmations, allocating and measuring of flowing gas, invoicing and statements of account, electronic delivery arrangements, and capacity release. The industry approved 140 of these in April 1996 and submitted them to FERC in response to FERC's Advance Notice of Proposed Rulemaking (RM96-1).[74] FERC adopted the 140 standards on July 17, 1996. Some pipeline companies are required to implement the standards by April 1, others by May 1, and all by June 1, 1997.

- **The Internet is being used by the natural gas industry mainly as an advertising medium to publicize specific company services**. Users can typically find information about a company's capabilities on its "home page" and order services, but are unable to obtain "real-time" information. Having learned from the problems resulting from the differing electronic systems in the natural gas industry, FERC has mandated that electric power companies use a network that is accessible to all power companies. As a result of that April 1996 mandate, a limited access, electric power internet is being established, using existing Internet software and dedicated servers (see Figure 13).

- **GISB's Future Technology Task Force has proposed that all jurisdictional pipeline companies place capacity release and other EBB information on the public Internet.** On September 30, 1996, the task force recommended that FERC approve adoption of 10 new electronic delivery mechanism standards and require all transportation service providers and their trading partners to have standardized transaction datasets by April 1997. Information currently on EBBs would become available on each company's Internet home page.

Figure 13. Electric Restructuring Begins in Earnest

FERC has issued orders to open electric transmission access

FERC Electric Restructuring Orders
Issued April 24, 1996

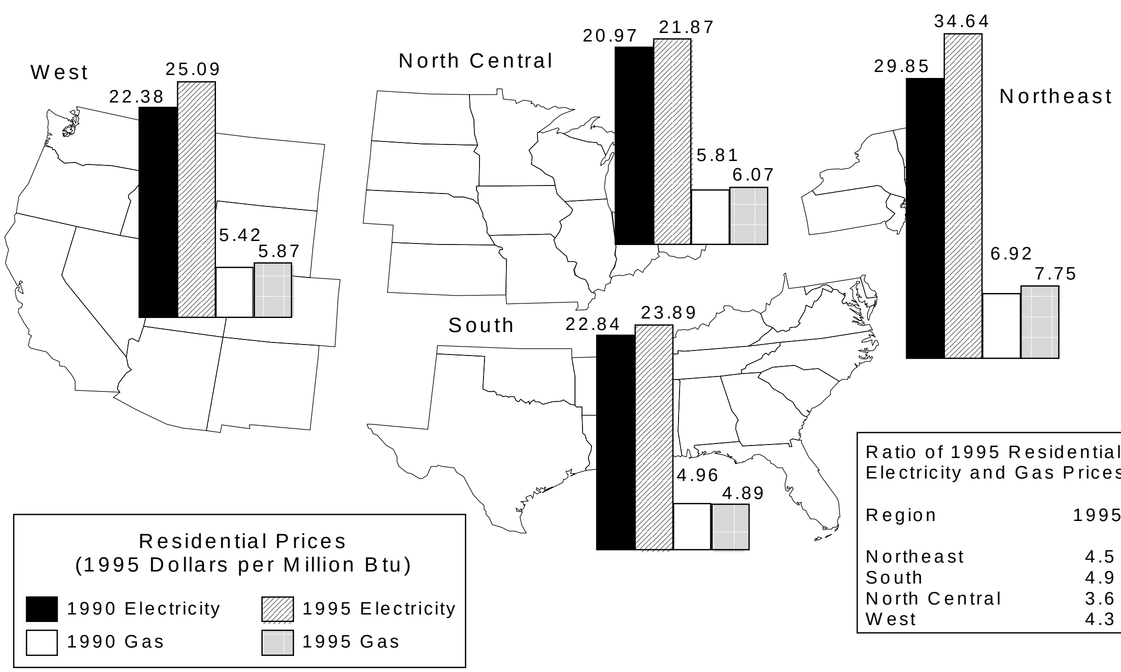
Order 888
Nondiscriminatory Open Access Transmission

- Requires public utilities to provide open access transmission services
- Requires functional unbundling of power and transmission sales
- Provides for full recovery of wholesale stranded costs from departing customers
- Requires a compliance tariff be filed by 7-9-96
- Requires companies to apply tariff terms to its own transactions for comparability
- Requires new wholesale sales contracts to be unbundled after 12-31-96
- Requires public utility holding companies to apply tariffs to all intracompany transactions by 12-31-96
- Proposes replacing compliance tariffs with capacity reservation tariffs by 12-31-97

Order 889
Open Access Same-time Information System (OASIS)

- Requires transmission owners to provide information on available transmission capacity, conditions, and prices
- Transmission information must be on the Internet system
- Sets communication protocols
- Requires capability to handle service requests and responses on line
- Requires the "First Phase" to be operational by 11-1-96
- Sets out "Standards of Conduct" for transmission owners

Residential consumers pay about four times more for electricity than gas[1]



Ratio of 1995 Residential Electricity and Gas Prices

Region	1995
Northeast	4.5
South	4.9
North Central	3.6
West	4.3

[1]In choosing fuels, consumers consider relative energy conversion efficiencies when comparing fuel prices. Energy efficiencies vary depending on the process, equipment, and pattern of use. Therefore, price adjustments are made for each type of energy application.

FERC = Federal Energy Regulatory Commission.

Note: Values expressed in 1995 dollars based on chain-weighted gross domestic product (GDP) deflator from the U.S. Department of Commerce.

Sources: Energy Information Administration (EIA), Office of Oil and Gas. **Electricity Prices:** derived from *Electric Power Annual 1996* (July 1996) and *Electric Sale and Revenue, 1990* (November 1991). **Gas Prices:** derived from *Natural Gas Annual 1995* (November 1996).

Key Issues: Electric Restructuring and the Gas Industry

The restructuring of the electric utility industry will open a new and challenging era of changes in energy industries. These changes are likely to affect not only the demand for natural gas for power generation but also the organization of the energy supply industries and conditions under which gas competes directly with electricity for end-use sales. The time table and the final results remain uncertain today; however, current activities do provide some insights into the transition.

- **The Federal Energy Regulatory Commission (FERC) has followed through on the 1992 Energy Policy Act by requiring transmitting electric utilities to provide open access transmission services.** Order 888, the open access rule, is similar to Order 636 that encouraged gas pipeline companies to become open providers of gas transportation services. As it did in the gas industry, FERC will require transmission-owning utilities to separate power sales functionally from the provision of transportation services. In a companion rule, Order 889, FERC set ground rules for the establishment of an electronic communications system to inform potential transmission customers of the availability and conditions of the transmission network (Figure 13).

- **Many of the forthcoming changes in the electric industry will follow the pattern set earlier by the natural gas industry; however, differences in the traditional organization of the two industries cause new problems.** Two differences that affect the pattern of restructuring are the degree of vertical integration and the amount of overvalued assets on regulated companies' books, commonly referred to as "stranded costs."[75] Traditionally, different companies own and operate each stage of the natural gas industry. For example, there are separate production, transmission, and distribution companies. But in the electric industry, multiple stages of the industry are controlled under one firm, from power generation through final distribution. This vertical integration complicates restructuring in several ways. Most noticeably, it results in splitting regulatory oversight for the different stages in a single company between Federal and State governments. This split jurisdiction is a major consideration in resolving the stranded costs problem. Estimates of potential stranded costs of electric utilities run as high as $300 billion.[76] FERC has determined that electric utilities are entitled to full recovery of the costs incurred to serve wholesale customers that are under Federal jurisdiction.[77] However, currently about 85 percent of stranded costs fall under State jurisdiction.[78] This past summer, legislation was introduced to give FERC authority over retail access if it is not competitive by December 15, 2000.[79]
- **The amount, proportion, and means of recovering stranded costs will determine just how soon competition reaches electricity markets.** If stranded costs are large and they must be recovered from customers rather than shared between customers and the utility companies, few customers will be able to change suppliers. Instead, retail customers will stay with their traditional utility supplier until stranded costs are nearly paid off.[80] Thus, the rate at which competition becomes established in retail markets will be tied to the way stranded costs are resolved.

- **Other aspects of electric restructuring may imply a closer and more favorable future for both industries.** Innovative developments in the gas industry during the past 10 years foretell some of these changes. Gas marketers have reformed gas supply relationships. Many of these same marketers are moving into the new electricity markets (see p. 23). Indeed, the largest gas marketer, Enron, is also now the country's largest electricity marketer. Enron has also proposed buying a major electric utility, Portland General. Although this is a merger between a major gas player and an electric utility, it is only one in the rush of recent merger proposals that have involved electric utilities. In an effort to create integrated "energy" markets as opposed to continuing separate, isolated markets, other gas and electric companies are also forming mergers or strategic alliances to give customers menus that allow buyers to bridge the differences between the industries. The electric business also appears to have caught the attention of the financial community. The development of financial instruments already used in the gas industry, such as spot, forward, futures, and options markets, are being taken as models for electricity.[81] These financial markets are probably the best means of bringing about the integration of energy markets.

- **In electricity as in gas, the first retail consumers to have choice among suppliers will be the high volume customers.** These customers tend to be very price sensitive. If market pricing significantly lowers electricity prices to these users, it could lead to the substitution of electricity for gas in industrial processes and undercut gas sales to manufacturers. However, in many other uses such as residential service, electricity is about four times more expensive than gas before adjustments for conversion efficiency (Figure 13).[82] Opportunities for electricity to attract new customers or to displace existing gas sales in these markets are less likely given the wide gas-price advantage.

Chapter 1 Endnotes

1. In general, prices are presented in nominal dollars for short-term, such as monthly, comparisons. For longer term comparisons over several years, such as in Chapter 5, prices are presented in real 1995 dollars using the chain-weighted gross domestic product (GDP) price index from the U.S. Department of Commerce, Bureau of Economic Analysis.

2. Spot prices are more commonly given in dollars per million Btu. In this section, spot prices were converted to dollars per thousand cubic feet, using the factor of 1,028 Btu per cubic foot, to aid in comparison of spot and wellhead prices.

3. During the second half of the 1980's, monthly average wellhead prices tended to rise throughout the fall and early winter, peak in January, and then fall until mid or late summer. This pattern has not held true during the 1990's, yet a 3-month pattern from December through February did develop wherein prices fall from the December level through February of the next year. However, the pattern occurred at very different levels of price in each year. Also, monthly price movements during the other months in those years were quite varied. Preliminary estimates indicate that even this shorter term monthly price pattern did not occur from December 1995 through February 1996.

4. By historical standards, stocks of gas were very low during the 1995-96 heating season, but stocks of substitute sources of energy such as oil and propane were also low. These low levels for stocks contributed to great price uncertainty.

5. For example, a customer will pay more for gas if it is able to get transportation at a discount. Thus, the final price of gas to an end-use customer may be influenced by whether a pipeline system used to transport the gas is operating near full capacity because this would affect the cost of transportation on that system. Moreover, if a pipeline is operating at or near full capacity, a company may hurriedly complete a deal and pay more for gas than it would otherwise in order to reserve sufficient space on the pipeline system.

6. Interestingly, because futures and options contracts enable a buyer and a seller of gas to obtain protection from current price increases, buyers and sellers have the choice to use such markets to protect their capability to make needed investment decisions instead of subjecting themselves to the challenges posed by the current uncertainty in gas prices.

7. More precisely, volatility is defined as the standard deviation of percentage price changes. The computed number is usually annualized. Thus, when daily price changes are used as primary data, the standard deviation is multiplied by the square root of 250, which is the number of trading days in a year.

8. The price of the options contract at the time it is sold is influenced by the volatility of the futures price. The higher the volatility, the higher the price of the options contract.

9. *Deep water* refers to water depths of 200 meters or more. Additional discussion of gas developments in the deep water regions can be found in a separate section of this chapter.

10. Additional information regarding this technology can be found in "Production Operations Moving to 5-D," *The American Oil and Gas Reporter* (February 1996).

11. Energy Information Administration, Office of Oil and Gas, "Crosswell Seismology—A View from Aside," draft paper (October 1996).

12. *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.

13. *Undiscovered resources* are located outside oil and gas fields in which the presence of resources has been confirmed by exploratory drilling, and thus exclude reserves and reserve extensions; however, they include resources from undiscovered pools within confirmed fields to the extent that such resources occur as unrelated accumulations controlled by distinctly separate structural features or stratigraphic conditions. *Technically recoverable resources* are those volumes producible with current recovery technology and efficiency but without reference to economic viability. *Economically recoverable resources* are those volumes considered to be of sufficient size and quality for their production to be commercially profitable by current technologies, under specified economic assumptions.

14. All proved reserves estimates cited in this section are from the Energy Information Administration, *Advance Summary, U.S. Crude Oil, Natural Gas, and Natural Gas Liquids: 1995 Annual Report,* DOE/EIA-0216(95)Advance Summary (Washington, DC, October 1996).

15. *Total discoveries* are calculated as the sum of new field discoveries, new reservoir discoveries in old fields, and extensions.

16. *Nonassociated natural gas* is natural gas not in contact with significant quantities of crude oil in a 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).

17. The estimated recovery volume data from the U.S. Geological Survey are for conventional resources in undiscovered gas and oil fields in onshore and State offshore areas of the conterminous United States. Thus, the estimates exclude substantial gas volumes that are expected to be recoverable from either unconventional resources, such as coalbed methane gas, or gas in the deep water areas of the Gulf of Mexico.

18. Unit cost estimates are based on an assumed 12 percent after-tax rate of return.

19. See Appendix A for a map defining the U.S. Geological Survey regions. These regions are aggregations of geological provinces, so they do not relate reliably to other regions discussed elsewhere in this report.

20. U.S. Department of the Interior, *An Assessment of the Undiscovered Hydrocarbon Potential of the Nation's Outer Continental Shelf*, OCS Report MMS96-0034 (Washington, DC, June 1996).

21. Unless otherwise specified, all statistics cited in this section are contained in or derived from Energy Information Administration, *Natural Gas Monthly*, DOE/EIA-0130(96/11) (Washington, DC, November 1996).

22. Energy Information Administration, *Natural Gas Monthly*, DOE/EIA-0130(96/11) (Washington, DC, November 1996); *Monthly Energy Review*, DOE/EIA-0035(96/10) (Washington, DC, October 1996).

23. Data on short- and long-term imports came from U.S. Department of Energy, Office of Fossil Energy, *Natural Gas Imports and Exports, First Quarter Report, 1996*, DOE/FE-0347-1 (Washington, DC, undated), pp. I-ii. Prices are expressed in the report in terms of dollars per million Btu. These were converted to dollars per thousand cubic feet by applying the conversion factor 1,021 Btu per cubic foot for gas imported from Canada.

24. Regional import statistics were derived from import data from the U.S. Department of Energy, Office of Fossil Energy.

25. Pipeline utilization data are from Natural Resources Canada, Natural Gas Division, *Canadian Gas Exports in the U.S. Market: 1995 Evaluation & Outlook*, *March 1996* (Ottawa, Ontario, Canada, undated), pp. 10-11.

26. Expansion planning by Canadian (and U.S.) pipeline companies has been made more difficult in the past several years as the U.S. gas industry has been restructured. While pipeline companies were demanding long-term commitments from shippers to reduce the financial risks involved in pipeline construction projects, which are usually very expensive and can take years to complete, producers and others have declined such commitments. This reflects customers' general preference for short-term deals. As a consequence, a consortium of Canadian producers announced plans to build its own pipeline—the "Alliance" project, which would run from northeastern British Columbia through production areas in Alberta and on to the Chicago area. This initiative has drawn competitive responses from a number of pipeline companies, which have proposed additional projects to increase deliverability of Canadian gas into the United States.

27. U.S. Department of Energy, Office of Fossil Energy, *Natural Gas Imports and Exports, Fourth Quarter Report, 1995 (Imports and Exports Fourth Quarter 1995),* DOE/FE-0336-4 (Washington, DC, undated), p. vi.

28. Energy Information Administration, *Natural Gas Monthly*, DOE/EIA-0130(96/11), p. 15.

29. Energy Information Administration, Office of Integrated Analysis and Forecasting.

30. U.S. Department of Energy, Office of Fossil Energy, *Imports and Exports Fourth Quarter 1995,* p. vii.

31. Interregional projects included only one new pipeline, the bi-directional Bluewater pipeline between Michigan and Ontario, Canada, with a capacity of 250 million cubic feet per day (MMcf/d). The rest were expansion projects, including the Florida Gas Transmission expansion at 373 MMcf/d from Louisiana to Alabama, the Tennessee Gas Pipeline Company's Niagara Import Point expansion (92 MMcf/d), and the Northwest Pipeline Phase II expansion (120 MMcf/d), which added only 21 MMcf/d at the Canadian border crossing. The others were minor projects such as the Texas Eastern Pipeline expansion from Lebanon, Ohio to the New Jersey/New York area (45 MMcf/d) and the Northern Natural IA-Il expansion of 22 MMcf/d. Between 1990 and 1994, interregional capacity increased by 10 billion cubic feet per day or by almost 14 percent. In 1992, 3,635 million cubic feet, or 5 percent of new capacity was added interregionally. During 1994 and 1995, additions to interregional capacity fell significantly.

32. Represents the sum of additional capacity as measured at each State-to-State crossing point for all pipeline projects shown on Figure 6. As can be seen on the map, several completed projects transited multiple States.

33. Compared with 1992 and 1993, additions to interstate capacity during 1994 and 1995 also fell significantly. On a State-to-State basis, interstate pipeline capacity increased by more than 10 percent with the largest increase also in 1992, a 4-percent change for 1992 and 1993.

34. See Energy Information Administration, *Natural Gas Monthly*, DOE/EIA-013(96/09) (Washington, DC, September 1996).

35. Based on net injections of 1,895 billion cubic feet between April 1 and September 30 in 1996, compared with 1,581 billion cubic feet for the same period in 1995. Calculated on the basis of injections only, the percentage increase was 13 percent between the two periods, 2,208 versus 1,951 billion cubic feet.

36. For the combined Eastern and Midwestern regions of the country, which depend upon underground storage to supplement natural gas supplies during often cold winters, EIA estimates that working gas levels at the start of the 1996-97 heating season will reach more than 1.7 trillion cubic feet. The estimate represents about 86 percent of total working gas capacity in these regions and about 94 percent of the average amount of working gas in storage at the beginning of the past three heating seasons.

37. From an operational standpoint, dipping into base gas in the short term is not detrimental and is considered normal practice at some underground storage sites, particularly late in the heating season. Just how much of the base gas inventory may be withdrawn without consequences depends upon the type of reservoir (aquifer and some water-driven reservoirs may be adversely affected if base gas is withdrawn) and the design specifications of the facilities.

38. Some of the increase in base gas dipping can also be attributed to the fact that FERC has allowed base gas inventory levels to be adjusted upward at a number of sites over the past several years, thus decreasing overall working gas capacity levels. Consequently, part of what is now being reported as base gas withdrawals was once within the working gas envelope.

39. See Energy Information Administration, "The Expanding Role of Underground Storage," *Natural Gas Monthly*, DOE/EIA-013(93/11) (Washington, DC, November 1993). In mid-1993, 68 proposed underground natural gas storage projects, to be completed between 1993 and 1996, had been announced or filed with the Federal Energy Regulatory Commission. Not all of these projects were implemented during the proposed time frame. Some were postponed or canceled. Of the 36 new sites proposed for development through 1995, 26 were completed and placed in service. Because a number of sites were abandoned during the same period and base gas inventory levels were adjusted at some existing sites, actual working gas capacity dropped slightly from 3,848 to 3,828 billion cubic feet from 1993 through 1995. However, because many of the new sites were high-deliverability, salt cavern storage sites, total daily deliverability increased 5,967 million cubic feet per day, or 9 percent.

40. See Energy Information Administration, *The Value of Underground Natural Gas Storage on Today's Natural Gas Industry*, DOE/EIA-0591 (Washington, DC, March 1995), Appendix B, Table B1.

41. Ten storage projects proposed to be implemented during 1994 or 1995 were canceled during the period.

42. Survey information collected by the Interstate Natural Gas Association of America (INGAA) as well as the Energy Information Administration (EIA) shows negligible sales by interstate pipeline companies in 1995. EIA data show that a small volume (13 billion cubic feet) of gas was sold by interstate pipeline companies in 1995, which represented only 0.2 percent of deliveries to end users.

43. While specific tariff provisions vary by pipeline company, no-notice service is generally a combination of storage and firm transportation services used to supply additional service upon the shipper's request. No-notice service is used to re-create the quality of service customers previously received through pipeline company sales service. It allows shippers to use their full capacity commitment without advanced scheduling. Local distribution companies frequently supplement their transportation portfolio with no-notice service in order to provide the most reliable service to their high priority customers. Released capacity and no-notice service represented 15 percent (3.3 trillion cubic feet (Tcf)) and 18 percent (4 Tcf), respectively, of total gas deliveries to market in 1995, a 15-percent and 29-percent increase over their respective 1994 levels. Energy Information Administration, Office of Oil and Gas, derived from Interstate Natural Gas Association of America, *Gas Transportation Through 1995* (September 1996).

44. Largely made up of local distribution companies (LDCs), local companies also include intrastate pipeline companies and producers who deliver gas directly to end users.

45. Energy Information Administration, Office of Oil and Gas, derived from Form EIA-176, “Annual Report of Natural and Supplemental Gas Supply and Disposition.”

46. The term “onsystem” refers to volumes and revenues associated with gas sold and delivered by the same entity.

47. In 1995, onsystem sales to commercial and industrial customers represented 77 percent and 24 percent of total deliveries, respectively, compared with 79 percent and 25 percent, respectively, in 1994. Total deliveries represent the total volume of gas delivered to consumers, including sales to and transportation for consumers. Onsystem deliveries to residential, commercial, and industrial customers, and total deliveries to electric utilities increased from 12.185 trillion cubic feet (Tcf) in 1994 to 12.434 Tcf in 1995, an increase of 2 percent. Energy Information Administration, Office of Oil and Gas, derived from *Natural Gas Annual 1995*, DOE/EIA-0131(95) (Washington, DC, November 1996).

48. Between 1994 and 1995, the unit transmission and distribution cost for residential, commercial, and industrial sales decreased by 3.4 percent, 4.6 percent, and 5.7 percent, respectively. The unit transmission and distribution cost for total deliveries to electric utilities increased by 7 percent. Energy Information Administration, Office of Oil and Gas, derived from *Natural Gas Annual 1995* (November 1996).

49. Unless otherwise stated, annual data in this section come from Energy Information Administration (EIA), *Natural Gas Annual 1995*, DOE/EIA-0131(95) (Washington, DC, November 1996), Table 1, and monthly data come from EIA, *Natural Gas Monthly*, DOE/EIA-0130(96/11) (Washington, DC, November 1996), Tables 3 and 4.

50. Data on natural gas consumption are available beginning in 1930. In 1972, 19,880 billion cubic feet of natural gas was consumed by end users.

51. Heating degree days are gas home customer-weighted heating degree days provided in Energy Information Administration, *Natural Gas Monthly*, DOE/EIA-0130(95/04) and (96/04) (Washington, DC, April 1995 and 1996), pp. 71 and 72 in both issues.

52. Gas used in new homes included both natural gas and liquefied petroleum gas. U.S. Department of Commerce, Bureau of the Census, *Housing Completions Report 1995*, C22/96-6 (Washington, DC, June 1996), p. 8, Table 7A.

53. Energy Information Administration price data are for onsystem sales only in the residential, commercial, and industrial sectors. Virtually all residential consumption is through onsystem sales, thus residential prices represent total deliveries in this sector. The proportion of consumption that is onsystem in the commercial and industrial sectors has generally declined in recent years. In 1995, 77 percent of commercial consumption was onsystem, while only 24 percent of industrial consumption was onsystem. The price of gas to electric utilities covers virtually all gas deliveries in this sector, whether onsystem or offsystem.

54. Energy Information Administration, Form EIA-867, “Annual Nonutility Power Producer Report.”

55. In this discussion, the fuel prices at each plant represent the average price for each type of fuel used at the plant. For example, a plant may use some residual and some distillate fuel oil to ignite coal. The price data would then include an average coal price and an average oil price for this plant.

56. Temperature data are the mean average daily temperatures in Kansas City, Missouri; Chicago, Illinois; Pittsburgh, Pennsylvania; and New York, New York. These cities were selected because they are representative of large gas markets in the areas affected by cold weather in both heating seasons.

57. Michigan Consolidated had its highest deliveries of gas in 20 years. ANR Pipeline experienced its most consecutive days (6) of over 5 billion cubic feet of throughput. Natural Gas Pipeline of America had its highest throughput in 15 years.

58. Several local distribution companies reported gas use that was 60 percent higher than normal for a day in January. Twelve pipeline companies met or exceeded record weekly throughput and eight pipeline companies set records for daily throughput.

59. Records on monthly storage withdrawals begin in September 1975. The highest monthly withdrawal was 805 billion cubic feet in December 1989.

60. Pasha Publications, Inc., *Gas Daily* (February 6, 7, and 9, 1996); and *Gas Daily’s NG* (April 1996). Imbalance penalties are extraordinary tariffs that a pipeline operator may impose on a transportation customer when that individual or organization fails to have the contracted volume in the pipeline’s system at the agreed-upon time (usually a daily measure).

61. For further discussion of the premium, see Energy Information Administration, *The Value of Underground Storage in Today’s Natural Gas Industry*, DOE/EIA-0591 (Washington, DC, March 1995), Chapter 2.

62. Pasha Publications, Inc., *Gas Daily* (January 23, 1996).

63. The citygate is the point at which the local distribution company takes receipt of gas.

64. Ben Schleisinger & Associates, *Directory of Natural Gas Marketing Service Companies*, 9th Ed. (1995).

65. Company applications to the Federal Energy Regulatory Commission.

66. Federal Energy Regulatory Commission, Docket No. RM95-6, *Alternatives to Traditional Cost-of-Service Ratemaking for Natural Gas Pipelines* (January 31, 1996).

67. Texas Eastern Transmission Corporation, Docket No. CP95-218 (January 31, 1996).

68. Federal Energy Regulatory Commission, Docket No. RM96-14-000, *Secondary Market Transactions on Interstate Natural Gas Pipelines* (July 31, 1996).

69. Bidding is required for all releases exceeding 31 days with rates less than the maximum tariff rate, and for rollovers of 31 days or less with rates less than the maximum tariff rate.

70. Deep water in the context of this report refers to water depths of 200 meters (roughly 656 feet) or greater.

71. *Oil Daily*, “Industry Takes Satellite out for Test Drive to Transmit Offshore Seismic Data to Land” (February 24, 1996) (http://www.newspage.com...223203.4od.tod00000.htm).

72. The Act pertains to projects in the Western and Central Planning Areas of the Gulf of Mexico and the portion of the Eastern Planning Area encompassing whole lease blocks lying west of 87 degrees, 30 minutes West longitude. Under the provisions of the Act, royalty payments are waived on the first 17.5 million barrel-of-oil-equivalent (BOE) produced in 200-400 meter waters, 52.5 million BOE in 400-800 meter waters, and 87.5 million BOE in water depths beyond 800 meters. (The 200, 400, and 800 meter thresholds are approximately 656, 1,312, and 2,625 feet.) This waiver is suspended in any year during which

crude oil prices exceed $28.00 per barrel or natural gas prices exceed $3.50 per million Btu.

73. These data are drawn from two articles: *Dallas Morning News*, “Deep-water oil lease bids surge” (April 26, 1996); and *Natural Gas Week*, “Royalty Relief, New Technology Spur Record-Setting Lease Sale” (April 29, 1996).

74. Foster Associates, Inc., *Foster Natural Gas Report*, No. 2075 (Washington, DC, April 11, 1996), p. 27.

75. Stranded costs are the value of utility activities that regulators allowed or even required companies to undertake that exceed the value that would be assessed to the activities in a competitive market.

76. Stranded cost estimates range from zero to about $300 billion, but industry supporters generally use estimates of about $135 billion.

77. Wholesale customers will be required to arrange to repay costs stranded on their behalf in order to gain access to the transmission network. The Federal Energy Regulatory Commission regulates about 15 percent of investor-owned electric utility revenues.

78. Debates on the disposition of State jurisdictional stranded costs are currently under way. Several States are experimenting with retail access programs modeled on programs to allow competing gas service.

79. H.R. 3790, The Electric Consumers Power to Choose Act of 1996. Committee review and floor debate have not yet occurred.

80. One example of the extent of the stranded costs problem is especially important to the gas industry. Many electric utilities want to include the excess cost of Public Utility Regulatory Policies Act of 1978 (PURPA) qualifying facility (QF) contracts in stranded costs. PURPA required electric utilities to purchase electricity generated by QFs at the utility’s avoided cost. In many States, avoided costs were set by administrative studies based on past utility-plant construction costs and expectations for escalating oil prices. These contracts allow QFs to sell power at prices that exceed current cost estimates. Since a majority of the power sold under these contracts is from gas-fired facilities, gas demand for nonutility generation could decline if electric utilities are not allowed to recover the cost of these contracts from final customers.

81. Building on its successful innovation in gas markets, the New York Mercantile Exchange (NYMEX) introduced electricity futures contracts for two separate West Coast markets in the spring of 1996. Progress in electricity futures trading is slow because of the lack of well-developed spot markets against which futures prices could be leveraged.

82. Detailed information about the specific energy-consuming activity and equipment would be needed to make efficiency adjustments for more direct price comparisons.