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Natural Gas 1995

Issues and Trends

November 1995

Energy Information Administration
Office of Oil and Gas
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Preface

Natural Gas 1995: Issues and Trends has been prepared by the Energy Information Administration (EIA) to provide a summary of the latest data and information relating to the natural gas industry, including prices, production, transmission, consumption, and financial aspects of the industry. The report consists of six chapters and one appendix. Each chapter is designed to be self contained, resulting in some repetition of definitions and other background material. Each chapter is composed of a one-page introduction followed by several two-page sections of figures and text examining a particular topic within the subject area of the chapter. Because of this format, endnotes appear at the end of each chapter.

Chapter 1 examines the behavior of natural gas supply prices. Chapter 2 discusses the domestic supply industry and issues concerning the North American supply market. Chapter 3 examines issues related to natural gas transmission, particularly the development of a secondary market for pipeline capacity trading. Chapter 4 presents data on current pipeline and storage capacity and plans for future expansion. Chapter 5 examines end-use markets and notes the areas most likely to be affected by the impending restructuring of the electric generation industry. Chapter 6 presents information on the financial performance of various segments of the natural gas industry, and Appendix A documents the methodology used in this analysis.

Unless otherwise stated, historical data through 1993 on natural gas production, consumption, and price come from EIA, *Natural Gas Annual 1993*, DOE/EIA-0131(93) (Washington, DC, October 1994) and *Natural Gas Annual 1992*, Vol. 2, DOE/EIA-0131(92)/2 (Washington, DC, November 1993). Similar annual data for 1994 and monthly data for 1994 and 1995 come from EIA, *Natural Gas Monthly* (*NGM*), DOE/EIA-0130 (95/07) (Washington, DC, July 1995). Data from the *NGM* are preliminary.

Natural Gas 1995: Issues and Trends was prepared by the Energy Information Administration, Office of Oil and Gas, under the direction of Diane W. Lique (202/586-6401). General information concerning this report may be obtained from Joan E. Heinkel (202/586-4680), Director of the Reserves and Natural Gas Division. Detailed questions on specific sections of the publication may be addressed to the following analysts:

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Many figures are composed of multiple illustrations. Below each figure title there is a list of subtitles describing each illustration. The subtitles are listed in the order in which the illustrations appear in the figure, from left to right moving down the page.

Executive Summary

Natural Gas 1995: Issues and Trends addresses current issues affecting the natural gas industry and markets. Highlights of recent trends include the following:

- Natural gas wellhead prices generally declined throughout 1994 and showed a sharp decline of 20 percent from July through October. For 1995, prices through May have averaged 22 percent below the year-earlier level (Figure ES1).

- The seasonal patterns of natural gas production and wellhead prices have been significantly reduced during the past 3 years despite the continuation of highly seasonal consumption patterns. Reduced seasonality has resulted in improved utilization of production facilities.

- Natural gas production rose 15 percent from 1985 through 1994, reaching 18.8 trillion cubic feet, while real wellhead prices and proved reserves declined by 45 and 3 percent, respectively. These changes provide strong evidence that a combination of improved efficiency and technology has fundamentally altered the gas supply process by allowing more gas to be extracted (relative to proved reserves) at lower unit costs.

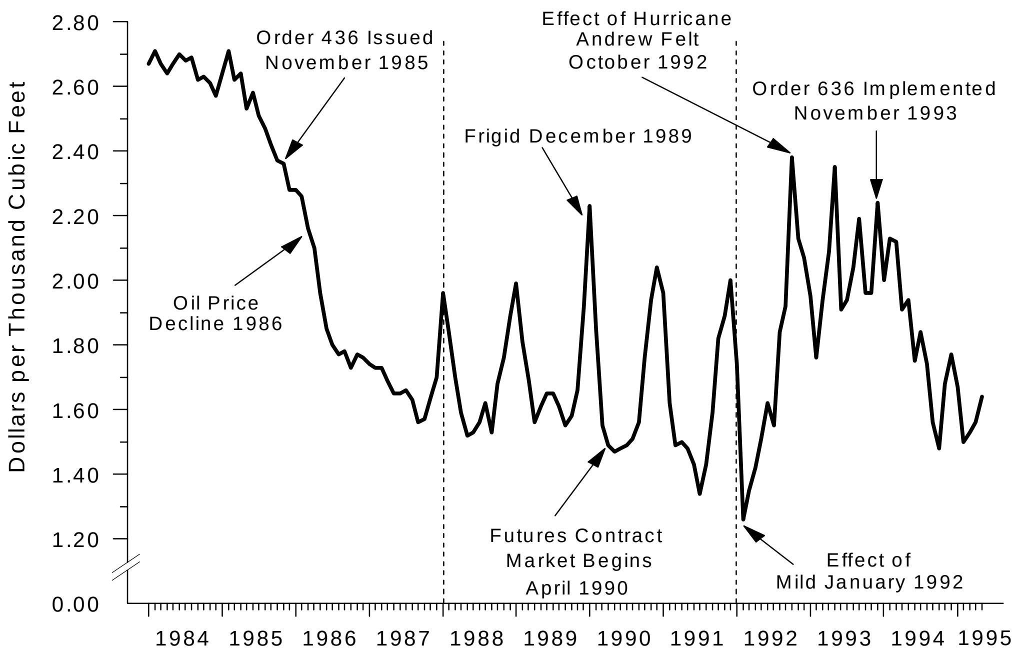
- Increasing amounts of natural gas have been imported, even as domestic production has continued its upward trend of the past 8 years. The Northeast and Pacific regions now depend on Canadian supplies for more than one-third of their consumption.

- Since 1985, lower costs of producing and transporting natural gas have benefited consumers. By 1994, the average price paid by residential consumers in real terms (1994 dollars) was 22 percent below the 1985 price. The average price paid by electric utilities declined by more than 50 percent during the period.

- Consumers may see additional benefits as States examine regulatory changes aimed at increasing the efficiency of the local distribution systems and providing consumers more choice and flexibility in their natural gas service.

- The electric industry, projected to be a major growth market for natural gas, is being restructured in a fashion similar to the recent restructuring of the natural gas industry. Changes in electric industry efficiency and productivity will determine the need for new generating capacity and, hence, the role of gas in meeting future electricity demand.

Figure ES1. Wellhead Price Patterns Have Changed Dramatically



Note: Data for 1994 and 1995 are preliminary.

Sources: Energy Information Administration. **1984-1992**—*Historical Monthly Energy Review, 1973-1992*. **1993-May 1995**—*Natural Gas Monthly* (August 1995).

- Gas companies are diversifying into other energy services and forming strategic alliances to increase business opportunities in both regulated and unregulated services.

After Increasing in 1992 and 1993, Wellhead Prices Have Trended Downward

Average wellhead prices generally declined throughout 1994 and the first 5 months of 1995, reversing the brief upward trend in 1992 and early 1993. Wellhead prices averaged $1.83 per thousand cubic feet in 1994, a 10-percent decrease from 1993. Over the past decade, the wellhead price has dropped in real terms by 50 percent.

The responsiveness of monthly wellhead prices to today's market conditions reflects the substantial changes in the natural gas industry during the past decade. Since 1984, the industry has moved from a highly regulated environment, dominated by long-term contracts, to one where markets respond quickly to short-term shifts in supply and demand. The evolution of the market can be traced in distinct changes in the pattern of wellhead prices (Figure ES1). Between 1984 and 1987, prices fell steadily as many companies shed their long-term supply contracts that were priced above the market. In 1987, wellhead prices averaged $2.11 per thousand cubic feet (in 1994 dollars), a decline of 43 percent from the 1984 level of $3.69 per thousand cubic feet (1994 dollars). The movement to a lower price level was essentially completed by 1987, and wellhead prices then began to exhibit a regular seasonal pattern of higher prices during the heating season when demand is at its peak. By 1987 active short-term spot markets were in place throughout the United States, providing the industry with much needed information on the current value of gas under competitive conditions. During the period 1987 through 1992, seasonality appeared to dominate wellhead price movements. Since 1992, the seasonality in price movements has diminished, yet variability in monthly prices has continued.

The volatility of prices entails significant risks for buyers and sellers. Gas prices are generally considered to be very volatile, and more participants are using the futures market to manage price risk. Trading in the futures market continued at a brisk pace in 1994 and 1995; monthly trading of contracts on the futures market reached a new high in August 1995. However, the phenomenal rate of growth in the futures market since its inception in 1990 slowed considerably, suggesting a maturing of the market. After doubling from 1992 to 1993, open interest (the average number of outstanding contracts on a daily basis) grew by only 12 percent between 1993 and 1994. Further growth may result from development of a second futures contract offered by the Kansas City Board of Trade for delivery in West Texas and the extension of the New York Mercantile Exchange Natural Gas Futures contract from 18 to 36 future delivery months.

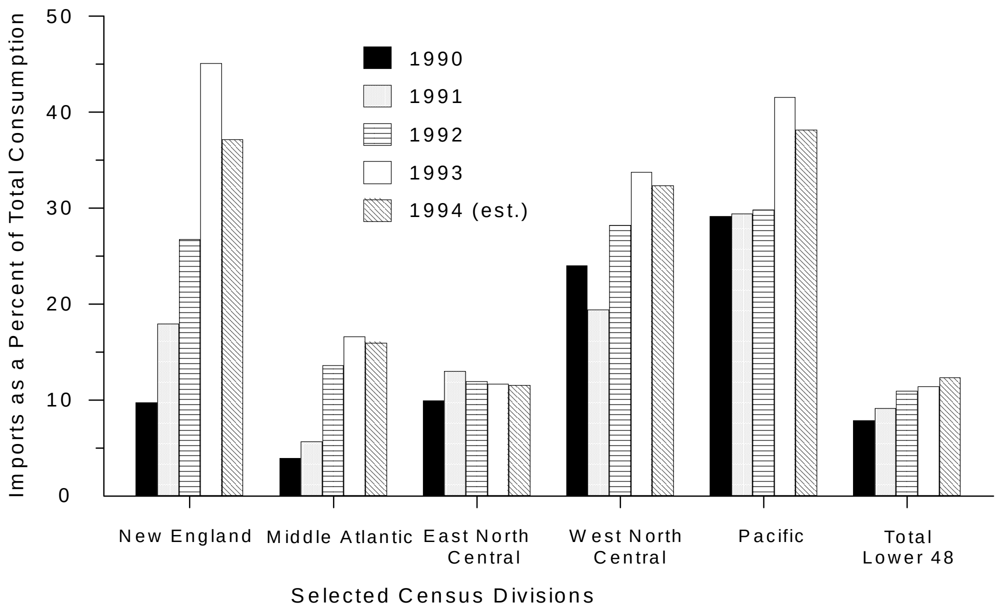
For producers looking at longer-term price patterns for investment in drilling activities, the real price of natural gas from 1987 through 1994 averaged $1.94 per thousand cubic feet (1994 dollars). Gas drilling in 1994 showed a general upward trend during the year, yet averaged below the 1993 level. The highest gas wellhead prices in 5 years had provided the stimulus for the upturn in drilling in 1993. Although 8,833 gas wells were completed in 1994, the strong gas drilling performance in early 1993 overshadowed 1994 drilling activity. For the first 7 months of 1995, gas drilling drifted below year-ago levels. For the near term, movements in the futures market suggest that the market's perception of both current and future supplies has become increasingly robust relative to expected demand. In 1995, the expected futures contract price, as measured by a weighted average price of all futures contracts, has been significantly below 1994 levels.

Integration of the North American Market Provides the United States Access to Plentiful and Diverse Gas Supplies

The natural gas transmission and distribution system across North America has achieved a fair degree of physical integration that benefits both producers and consumers. Canada is the dominant trading partner of the United States for natural gas. Mexico has the potential for exporting significant volumes to the United States, but it is likely to remain a net importer of gas for years to come because of a lack of development of its productive capacity and supporting infrastructure. Liquefied natural gas (LNG) imports have some regional significance for U.S. markets, but the aggregate volumes supplied are small because of the relatively low U.S. natural gas prices.

The Canadian presence is an increasingly important aspect of the U.S. gas market and is putting competitive pressure on the domestic industry. During the past 5 years, pipeline capacity from Canada into the United States increased by nearly 60 percent. Today some regions of the United States are heavily dependent upon Canadian supplies (Figure ES2). For example, with the construction of additional pipeline capacity into the Northeast, the share of Canadian gas used to meet demand in New England climbed from 10 percent in 1990 to 37 percent in 1994. The Western Region (principally California) has increased pipeline import capacity by 47 percent since 1990. During the past 2 years, imported supplies from Canada provided about 40 percent of consumption in California, Oregon, and Washington. Currently, imports from Canada are near the upper limit of the existing pipelines' capacity to transport gas into the United States. Capacity utilization on Canadian exporting pipelines averaged

Figure ES2. Some U.S. Areas Rely Heavily on Canadian Gas



Sources: Energy Information Administration, Office of Oil and Gas, derived from: *Natural Gas Monthly* (August 1995), *Natural Gas Annual 1993* (October 1994), and import and export data from U.S. Department of Energy, Office of Fossil Energy.

82 percent for the period November 1993 through October 1994, with even higher rates during peak-demand periods. Utilization rates on lines into the Northeast and Midwest Census regions exceeded 90 percent for the same period.

A decade ago, Canada exported 28 percent of its production to the United States. In 1994, Canada exported 50 percent, 2.6 trillion cubic feet, an increase of 13 percent from the level in 1993. Canadian production has been increasing since 1986 despite gradual declines in reserve stocks. The increase in production was due to more intense field development and was accompanied by a substantial decline in the Canadian reserves-to-production (R/P) ratios. The R/P ratio for the Western Canadian Sedimentary Basin declined from 29.2 in 1983 to 14.6 by 1993.

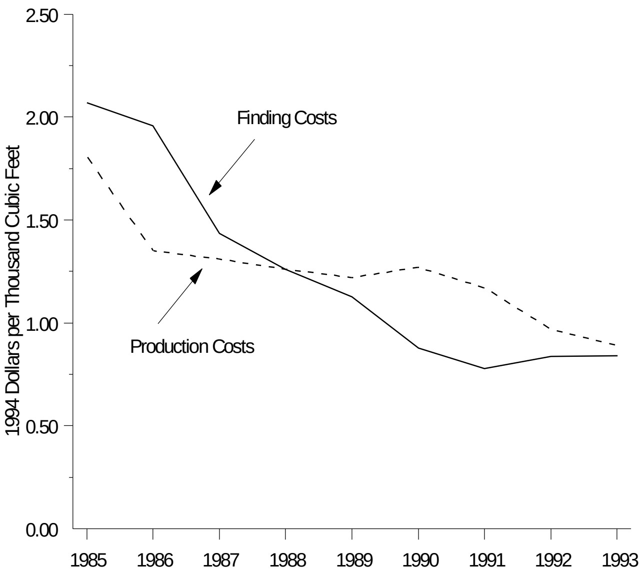
Canada's place as a significant supplier of U.S. gas requirements seems secure for years to come. The specific role of other foreign supplies, via pipeline from Mexico and LNG tanker from other countries, is quite uncertain at present. However, the abundance of overall supplies should support U.S. market growth over the near term without substantial price increases.

Efficiency Improvements Have Reduced the Costs of Finding and Moving Natural Gas

Changing market dynamics provide continuing pressure on all segments of the natural gas industry to cut costs and improve the efficiency of their operations. The reaction of the producers has been dramatic. The increase in domestic production despite relatively low prices underscores the adjustments that have taken place in the industry during the past decade. Domestic production in 1994 reached 18.8 trillion cubic feet (Tcf), a 3-percent increase from the level in 1993. Since the low point in 1986, production has risen by 2.8 Tcf, reaching the highest level since 1981. Idle productive capacity has been reduced substantially. For January 1987, more than 30 percent of the Nation's natural gas productive capacity lay idle. By January 1995, idle capacity is estimated to be 12 percent.

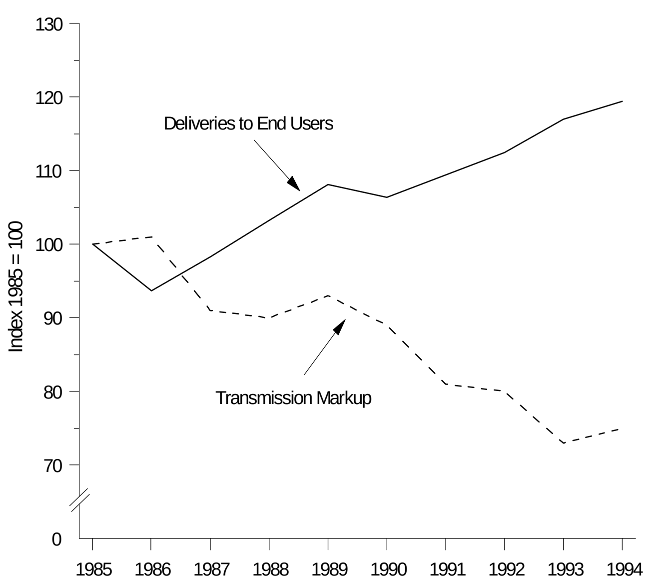
Recent production increases reflect the combined benefits of efficiency gains and improved technology. For example, the 1993 costs of finding and producing onshore natural gas were less than half the costs in 1985. (These comparisons, made in 1994 dollars, are for the major integrated oil and gas producing companies as well as large independent firms included in the Energy Information Administration's Financial Reporting System (FRS).) Increased drilling productivity has lowered average onshore finding costs by 59 percent to $0.86 per thousand cubic feet in 1993 from $2.11 per thousand cubic feet in 1985. (The oil portion of these costs was converted to a natural gas equivalent, Figure ES3.) In addition, many firms have become more production cost efficient as indicated by the 51-percent decline in average onshore production costs in the lower 48 States for the FRS firms between 1985 and 1993. Average production costs for

Figure ES3. Producers Achieve Substantial Reductions in Finding and Production Costs



Source: Energy Information Administration (EIA), Office of Oil and Gas, derived from: Form EIA-28, "Financial Reporting System."

Figure ES4. Natural Gas Transmission Markups Have Declined as Deliveries Increased



Note: The transmission markup is calculated as the difference between the average citygate price and the average wellhead price.

Sources: Energy Information Administration, Office of Oil and Gas, derived from: **1985-1988**—*Historical Monthly Energy Review* (August 1994); **1989-1994**—*Natural Gas Monthly* (August 1995).

all FRS firms in 1992 and 1993 were no more than $1.00 per thousand cubic feet. The lowest cost for any FRS firm was $0.48 per thousand cubic feet.

Operational improvements have occurred in the interstate transmission of natural gas. Open access has contributed to higher throughput and lower transmission markups (Figure ES4), and the emergence of the secondary capacity market has increased pipeline system efficiency by providing shippers with competitive alternatives to traditional pipeline services. While total deliveries to end users increased by more than 19 percent during the period 1985 through 1994, the transmission markup declined by 25 percent, from $1.66 per thousand cubic feet (in 1994 dollars) in 1985 to $1.25 per thousand cubic feet in 1994. The markup is measured as the difference between the wellhead price and the price paid by local distribution companies (LDC's). In fact, the average price for transmission services may have declined even further, because the price paid by LDC's represents only a portion of the market (principally residential and commercial consumers) and excludes most industrial and electric utility consumption. Between 1985 and 1992, operation and maintenance expenses (for a sample of 25 major interstate pipeline companies) declined 29 percent to $0.10 per thousand cubic feet of gas delivered, down from $0.14 per thousand cubic feet in 1985.

Although the Nation's consumption requirements remain seasonally driven, the seasonality of other segments of the industry has been reduced, resulting in higher utilization of wellhead and transmission facilities. Annual production volumes have grown, with much of the increase in the summer, off-peak months dedicated to storage injections, which serves to levelize production flows. Imports in 1994 remained relatively constant throughout the year instead of declining in the summer as they had in previous years. A key factor fostering these changes is the increasing integration of natural gas storage into the daily operations of the interstate transmission system. The role of storage has expanded beyond that of a strictly seasonal supply source, as industry changes have brought demands for new services and prompted the development of new storage facilities as well as upgrades to existing facilities. New storage capacity has increased substantially. Deliverability from storage has increased by 10 percent since 1990, and planned additions could increase peak-day deliverability by 23 percent by the end of the decade.

Natural gas consumers have benefited from the industry restructuring and the efficiency improvements in the production and transmission sectors. Between 1985 and 1994, as wellhead prices declined $1.52 per thousand cubic feet in real terms, average end-use prices also declined to varying degrees in the different end-use sectors. Residential and commercial customers, who have limited alternatives for the high-quality service they require and who typically purchase their gas service from LDC's, saw average prices drop $1.77 (22 percent) and $1.92 per thousand cubic feet (26 percent), respectively.

Electric utilities, with more flexibility in their fuel choices, saw the greatest decline—$2.47 per thousand cubic feet (52 percent).

Restructuring Continues as State Agencies Debate Regulatory Changes at the State Level

With significant cost reductions obtained in the supply and interstate transmission sectors, the States are addressing ways to improve the efficiency of their local distribution systems. Actions by State regulatory agencies will define the extent to which the policies adopted at the Federal level will be further extended to reach residential customers, thereby allowing them choice and flexibility in purchasing natural gas services. The extension of market flexibility to individual consumers raises complex issues of fairness, efficiency, and reliability. Resolution of these issues may vary from State to State.

State regulatory commissions and local distribution companies are employing both traditional regulatory solutions and innovative methods, such as performance-based ratemaking and flexible rates, to deal with competitive and operational changes in the intrastate market. Ten of the thirteen States reviewed in this report have issued guidelines for unbundling the distribution sector. The focus thus far has been on the industrial and large commercial customer classes. Some plans will include residential and small commercial customers in the future. Eventually, like the restructuring of the interstate transmission market, the end-user market may be quite different from the one in which consumers obtain their service today.

Electricity Industry Restructuring May Change the Outlook for Natural Gas

While utility electric output grew by only 1 percent in 1994, electric utility consumption of natural gas increased by 11 percent (about 300 billion cubic feet), the first notable increase in this sector since 1989. However, this increase was in part motivated by the lack of hydroelectric power resulting from drought conditions in the Northwest. Even with the 1994 increase, gas consumption in this sector has not yet returned to the level of a decade ago (3.1 trillion cubic feet in 1984). Also, the natural gas share of utility fuel consumption has diminished slightly, from 12 percent in 1984 to 10 percent in 1994.

The power generation market has long been considered the principal growth market for natural gas, with an annual rate of growth of 1.7 percent projected between 1994 and 2000. The recent rapid growth of nonutility generators (NUG's) and the high proportion of gas-fired generation in the NUG sector have contributed to these expectations. For example, in 1994 nonutility power generation grew by 6 percent, although still contributing only 11 percent of all generation.

An important issue for the industry is the ultimate impact of the restructuring of the electric power industry initiated by the Notice of Proposed Rulemaking issued by the Federal Energy Regulatory Commission in March 1995. Many believe that a newly competitive electric industry will continue to build large amounts of gas-fired generation. However, some conditions that have encouraged recent growth in gas-fired capacity additions may not hold as the electric power industry is restructured. If the Public Utility Regulatory Policies Act is repealed, as has been proposed, it will affect the returns and risks for NUG's and may dampen NUG development and the associated gas demand. Second, the movement toward greater reliance on market forces to determine electricity prices may lead to changes in industry productivity. This could affect the electric industry's pattern of demand for natural gas fuel as well as the demand for building additional gas-fired capacity.

Slowing Demand Growth Has Fostered a Strategic Movement into Diversified Subsidiaries

Growth in end-use consumption of natural gas is projected to slow to an annual rate of 1.0 percent over the period from 1994 through 2000. This is considerably slower than the 2.4 percent annual growth shown in the 7-year period from 1988 through 1994. Still, the evolving market structure provides many opportunities for companies to earn higher returns through unregulated subsidiaries and diversification into energy-related ventures. A number of strategic alliances have developed in which separate businesses team up in gas marketing, energy, and storage ventures to capitalize on additional opportunities. Some pipeline companies and LDC's have adopted a strategy to diversify into other energy services, rather than focusing exclusively on natural gas. For pipeline companies, the revenue contribution from these services is growing, while the revenue shares from the regulated transmission operations are declining. With the gradual introduction of citygate unbundling, distribution companies must contend with more competition in their service territories, prompting some to diversify as well.

Overall, a continued increase in competition will benefit the industry and consumers. The industry now has more flexibility to develop innovative approaches to providing consumers with the services they want, and to establish new roles in the increasingly unregulated "energy marketplace" of the future.

1. Natural Gas Supply Prices

At the core of the natural gas industry are active physical and financial markets where the commodity itself is priced. Improved price signals from the consumer to the supplier have been accomplished, in part, through legislative and regulatory initiatives. These actions included deregulation of wellhead prices, open access to the pipeline transportation and storage system, and separate pricing of the commodity and supporting services required to move gas from producing wells to households and factories. Now changes in market demand and supply are reflected in prices on futures and spot markets. While the competitive market structure ensures that short-term supply and demand are in balance, there is also always potential for significant price risk for both sellers and purchasers associated with sudden changes in market conditions from changes in weather and other factors.

The transition to a more market-oriented, less regulated environment has significantly affected business operations. Production sites and pipeline and storage services are much more accessible today, with a larger number of commercially interconnected facilities. The purchase and sale of the commodity at the wholesale level is now effectively deregulated. Regulation of interstate transportation continues, but with a rate structure designed to price separately different types of service. Thus, customers have the opportunity to pay for only the particular services and pipeline capacity they need for reliable gas service throughout the year. However, what the market now offers in flexibility is partially offset by the complexity of contracting for these services. Pipeline companies, with limited exceptions, are no longer allowed to bundle the sale of natural gas with transportation services. Instead, today marketing companies play a significant role in the aggregating of supplies and in the selling of services that had previously been provided by pipeline companies. Gas can now be obtained from numerous sources and transported along several pipelines. Contracting arrangements include short-term spot contracts, longer term contracts, futures contracts, and the exchange of futures for physicals. Gas can be purchased under fixed-price contracts or indexed to spot prices, futures prices, or alternative fuel prices. A significant unregulated swaps market also exists. Buyers and sellers participating in the swaps market can fix the cost of gas and the cost of transporting it between locations, thus guaranteeing a return or fixed cost for gas service.

This first chapter examines the physical and financial markets where the price of the commodity is set, looking at the interaction between the markets and how they complement each other. Chapters 2 through 6 have the same format as this chapter: an introductory page and several 2-page sections of figures and text highlighting particular issues and trends. These five chapters address the following subjects:

- Reaction of the supply industry to the lower price environment and the increasingly North American character of the natural gas market

- Transformation of the transmission and distribution sector to a more service-oriented industry and some of the lingering regulatory issues affecting this sector

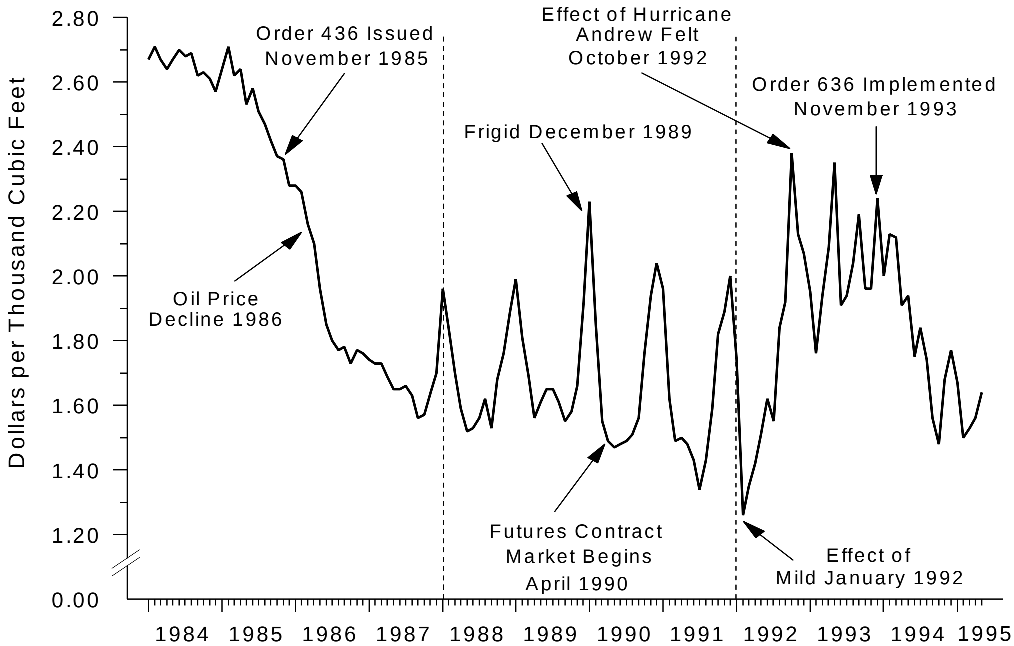
- Expansion of the pipeline system to serve new markets and provide the new services required by the industry

- Continuing trends in consumption patterns of natural gas and issues that the industry will be addressing as the electric generation industry is restructured

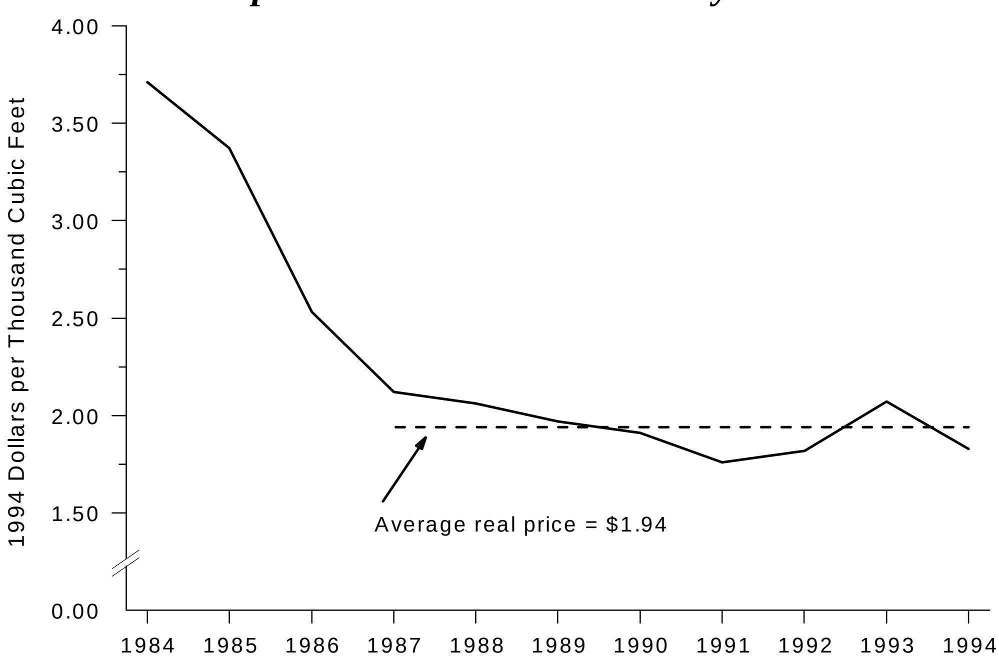
- Financial impacts on the industry segments as they trade in an increasingly competitive domestic and foreign marketplace.

Figure 1. Wellhead Price Patterns Have Changed Dramatically

Monthly price variability has increased



While annual prices have remained relatively low since 1987



Note: Data for 1994 and 1995 are preliminary.

Sources: Energy Information Administration. **1984-1992**—*Historical Monthly Energy Review, 1973-1992*. **1993-May 1995**—*Natural Gas Monthly* (August 1995).

Wellhead Prices: Past and Present

Average wellhead prices generally declined throughout 1994 and early 1995, reversing the brief upward trend in 1992 and early 1993. Prices peaked in February 1994 at $2.13 per thousand cubic feet (Mcf) following the record cold weather in January, and then generally declined until October 1994 when they reached $1.48 per Mcf. After a brief move upward, prices returned to this level in February 1995 and have remained relatively steady since then. Prices during the first 5 months of 1995 were down sharply, averaging almost $0.45 per Mcf less than year-earlier levels. Several factors contributed to the low prices during the past year, including: increased domestic production, record imports of Canadian gas, and higher storage levels because of milder-than-normal weather during most of the period.

The responsiveness of monthly wellhead prices to today's market conditions reflects the substantial changes in the natural gas industry during the past 12 years. Since 1984, the industry has moved from a highly regulated environment, dominated by long-term contracts, to one where markets respond quickly to short-term shifts in supply and demand. The evolution of the market is reflected in three distinct patterns of monthly wellhead price behavior, which correspond roughly to the periods 1984 through 1987, 1988 through 1991, and 1992 through mid-1995 (Figure 1). Throughout this time, the Federal Energy Regulatory Commission (FERC) issued a series of orders designed to further competition in the market. These efforts culminated in Order 636, which was implemented in November 1993.

- **Between 1984 and 1987, prices fell steadily as many companies shed their long-term supply contracts that were priced above the market**. In 1985, FERC issued Order 436, which opened access to pipeline systems for all possible buyers of gas and supported development of spot markets. Even before 1985 an increasing number of large industrial and electric utility customers were buying gas directly from producers rather than relying on pipeline companies for sales service. As more pipeline companies became solely providers of transportation service, they renegotiated many of their long-term, high-priced contracts with producers. With prices no longer propped up by long-term contracts, wellhead prices began to fall. In 1987, wellhead prices averaged $2.11 per Mcf (1994 dollars), a decline of 43 percent from the 1984 level of $3.69 (1994 dollars).

- **The movement to a new lower price level was essentially completed by 1987, and wellhead prices began to exhibit a regular seasonal pattern of higher prices during the heating season when demand is at its peak**. By 1987, active short-term spot markets were in place throughout the United States, providing the industry with much needed information on the current value of gas under competitive conditions. This allowed consumers and suppliers to respond to short-term influences on price, resulting in a more dynamic market.

- **The seasonality in price movements virtually disappeared from 1992 through mid-1995, yet variability in monthly prices continued**. Today, spot prices continue to respond to short-term shifts in demand and supply. When demand for natural gas increases significantly because of an unusual drop in temperature, such as occurred in January 1994, wellhead prices rise in response to the increased space-heating demand. However, these prices may also fall precipitously when normal temperatures return. Brief periods of relatively high prices represent significant opportunities for profit. Accordingly they disappear quickly as the industry responds by promptly bringing additional supplies of natural gas to market. High-deliverability storage and pipes, as well as imports of gas from Canada, have major roles in dampening price increases because additional gas can be quickly released to market when prices rise. Nonetheless, prices are still more likely to be higher in the winter than in the summer because of additional costs incurred in satisfying highly variable wintertime demands. Also, purchasers are more willing to pay higher prices when sudden temperature changes cause them to need gas immediately for space heating.

- **Although short-term price volatility has become the hallmark of today's wellhead market, prices on an annual basis have been fairly low in real terms since 1987, ranging from $1.76 to $2.11 per Mcf (Figure 1).** Wellhead prices averaged $1.83 per Mcf in 1994 and $1.58 through May 1995. For the remainder of 1995, wellhead prices are expected to stay relatively constant and then increase in the fourth quarter as the 1995-96 heating season gets underway. Barring extreme weather, the average wellhead price for 1995 is expected to average $1.68 per Mcf, declining 8 percent from 1994. The lower price is the result of production capability that by July 1995 was at least as large as in the previous year, combined with higher import capability and relatively little change in demand.

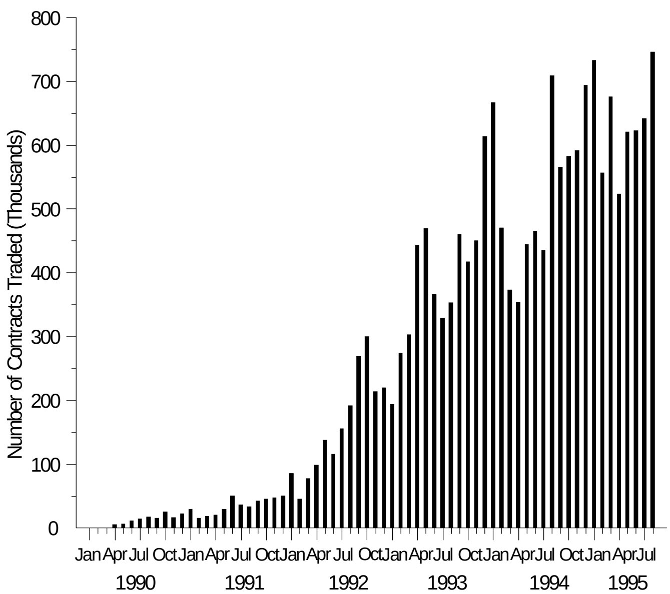
Changes in monthly wellhead price patterns are a consequence of better informed buyers with more choices. This has been supported by the growth in natural gas financial markets.

Figure 2. The Natural Gas Futures Market Matures

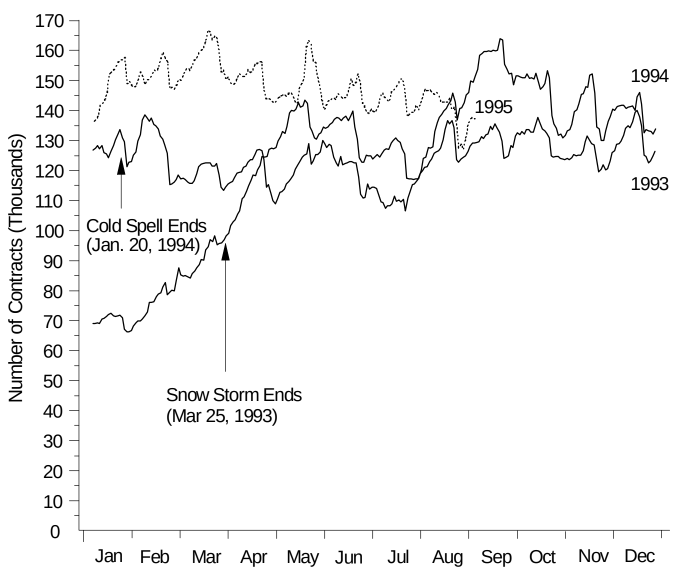
Price volatility for the nearby futures contract is great

Futures prices in 1994 and 1995 tended to be below year-earlier levels

The volume of trading continued to increase in 1995 . . .



. . . As did the number of contracts



Note: The nearby contract is the contract that is to terminate trading next on the futures market.
Source: Commodity Futures Trading Commission, Division of Economic Analysis.

Recent Futures Market Activities

Wellhead and spot prices were volatile during 1994 and the first half of 1995, and trading in the futures market continued at a brisk pace as market participants used futures contracts to manage price risk. Gas prices are generally considered to be very volatile, and more participants are using the futures market, both as hedgers and speculators.[1] Nonetheless, marketers who buy and sell gas for every sector of the industry are still the major users of the futures market. However, the phenomenal rate of growth in the futures market since its inception in 1990 slowed considerably, indicating that the market is maturing.

- **The price of the futures contract that is next to expire (nearby contract) is frequently used to begin negotiations for gas deliveries.**[2] Although the New York Mercantile Exchange (NYMEX) futures contract market extends for 36 delivery months, the nearby delivery month contract is of special interest. It helps establish a price for contracts that are finalized during "bid week"—the several days near the end of a month when arrangements are completed for firm deliveries during the next month. There is also no limit on the amount of daily price variability for the nearby contract in its final month of trading. During other months, contracts have a daily variability limit of $0.10.

- **The price of the nearby or short-term futures contract fell throughout much of 1994 and remained low in 1995 compared with year-earlier values.** Although prices rose sharply in response to cold weather in late January and early February 1994, reaching a high of $2.64 per million Btu on February 1, prices fell throughout much of the year (Figure 2). Between 1993 and 1994, domestic dry gas production grew by 3 percent and imports of relatively low-cost Canadian natural gas grew by 13 percent, putting downward pressure on prices. Milder-than-normal weather through the final three quarters of 1994 and the first quarter of 1995 kept residential and commercial consumption down and storage levels up. As a consequence, prices at mid-year 1995 were low relative to year-earlier levels.

- **The expected or long-term futures contract price, as measured by a weighted average of all futures contract prices,[3] has remained significantly below 1994 levels in 1995.** Since April 5, 1994, a weighted average price of all futures contract prices has been consistently below year-earlier values (Figure 2). The long-term prices in early April of 1993, 1994, and 1995 were about $2.40, $2.20, and $1.80 per million Btu, respectively. This suggests that the market's perception of both current and future supplies has become increasingly optimistic relative to expected demands.

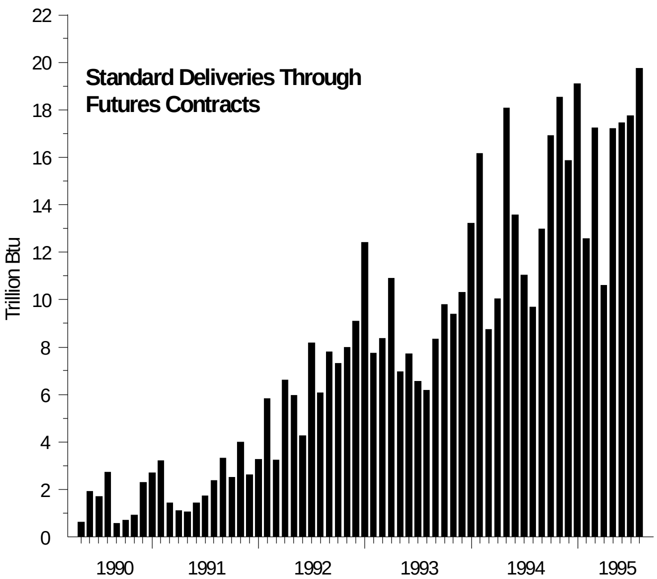
- **Monthly trading of contracts on the futures markets reached a new high in January 1995.** Trading volume has increased significantly since the market's inception, indicating that market liquidity is great. Although the rate of growth in the number of contracts traded has leveled off from the rate between 1990 and 1993, the volume of trade reached its highest level ever in August 1995 when it exceeded 700,000 contracts. The average number of contracts traded increased from 389,300 in 1993 to 529,170 in 1994. However, the volume of trade grew more slowly in 1994 and has remained relatively constant since August 1994. This may, in part, explain the closeness of the variability in the futures price between 1993 and 1994.[4] For the entire year, the average daily variability for the nearby futures price, as measured by the standard deviation, was $0.242 per million Btu for 1993 and $0.250 per million Btu for 1994.

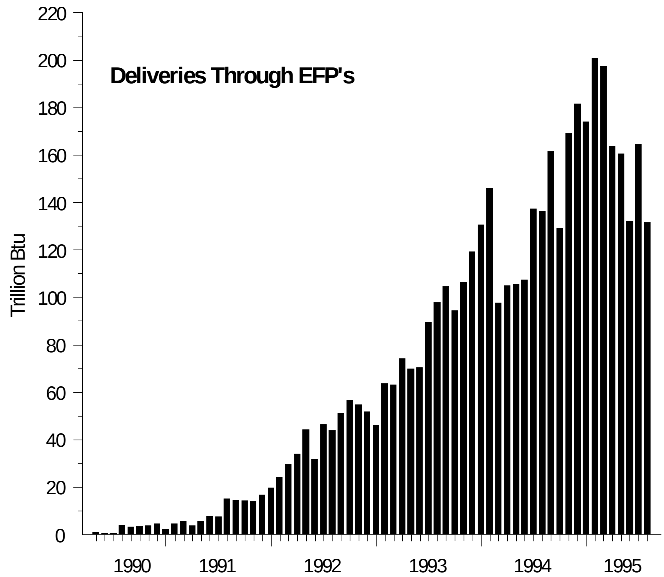
- **After doubling from 1992 to 1993, open interest grew by only 12 percent between 1993 and 1994.** The average daily amount of open interest (number of outstanding contracts) was 51,000 in 1992, 116,000 in 1993, and 130,000 in 1994 (Figure 2). Several factors may account for this slower growth. First, the futures market is of limited usefulness for buyers and sellers in the western and Canadian markets. This is because prices for delivery at the Henry Hub[5] versus delivery at western and Canadian markets (location basis risk[6]) are not closely aligned and are difficult to predict. Second, the increasingly popular options and swaps market,[7] which allows the hedging of price risk more than 18 months in the future, competes with the futures market as a risk management tool. These two limitations are being addressed by the formation of a new futures contract market and extension of the delivery months for the NYMEX contract. The new futures contract for delivery in west Texas began trading on the Kansas City Board of Trade on August 1, 1995. The NYMEX natural gas futures contract market was extended from 18 to 36 future delivery months beginning July 5, 1995.

The expanded services provided by NYMEX and the Kansas City Board of Trade will encourage continued growth in the futures market. Continued growth will also be affected by how closely futures prices at the end of trading correspond to spot prices for the same delivery month.

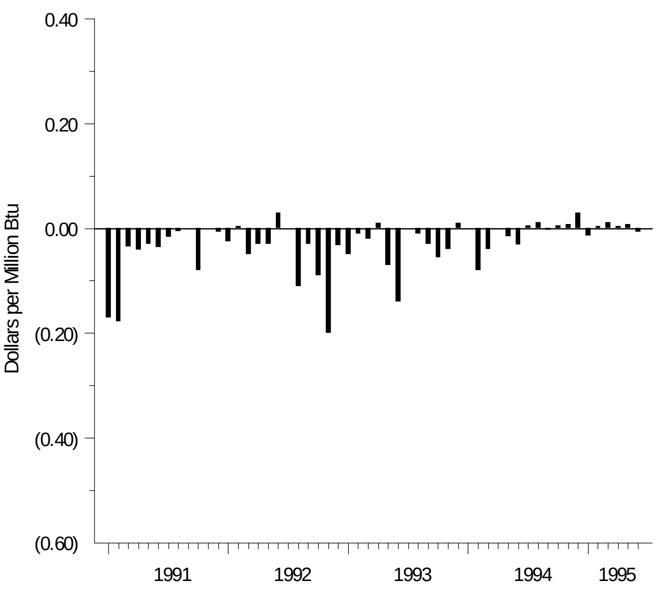
Figure 3. Deliveries Based on Futures Increased as the Difference Between Futures and Henry Hub Spot Prices Declined

. . . With most deliveries through EFP's

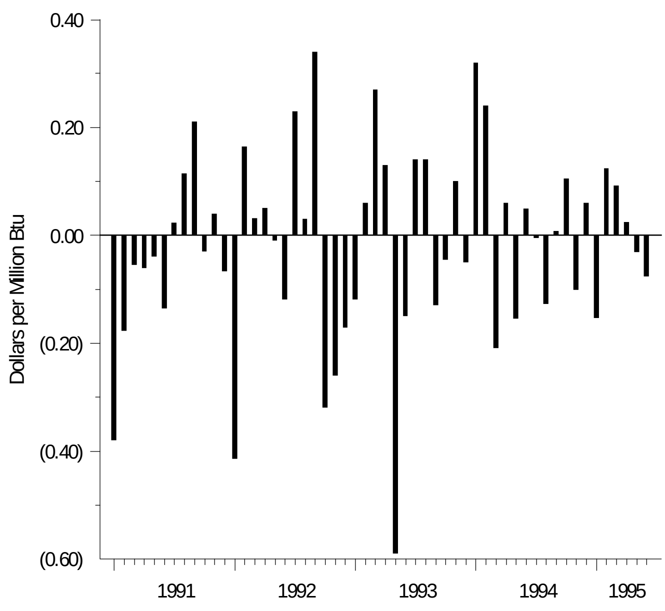




The difference in Henry Hub and futures price indicate spot prices are converging during bid week . . .



. . . But the differences are large for the entire delivery month



EFP = Exchange of Futures for Physicals.

Note: One unit on the "Through EFP's" scale represents 10 times the volume of one unit on the "Through Futures Contracts" scale.

Sources: **Deliveries:** Commodity Futures Trading Commission (CFTC), Division of Economic Analysis. **Price Differences:** Energy Information Administration, Office of Oil and Gas, derived from: Futures Prices—CFTC, Division of Economic Analysis; Henry Hub Bid Week Prices—McGraw Hill, *Inside F.E.R.C.'s Gas Market Report*, various issues; Henry Hub Delivery Month Prices—The Oil Daily Company, *Natural Gas Week*, various issues.

Futures Markets and Spot Markets

The natural gas futures contract market is primarily a financial market for hedging price risk. The value of the futures contract as a price hedging tool increases as the futures price at the close of trading for a delivery month converges to the spot price for the same delivery month. If the difference between the futures and spot prices is large and systematic, then traders will tend to use the futures contract to make or take delivery rather than as a tool for hedging price risk. For example, a supplier who establishes a futures contract position near the close of trading for the contract is likely to choose delivery if the price tends to be significantly higher than the average price for the delivery month.[8] However, some buyers and sellers of gas will use the futures contract for delivery even when the difference between the futures and spot prices is small, because of the quality of the delivery mechanism associated with the futures contract. The fact that the two price series have been converging while deliveries have tended to increase indicates the high value of the natural gas futures market both as a means of price discovery and of effecting delivery.

- **Most deliveries based on futures contracts are through Exchanges of Futures for Physicals (EFP's), which were more than 10 times the volumes delivered through standard futures contracts in early 1995 (Figure 3).** Deliveries have increased through both mechanisms, but in early 1995, deliveries arranged through EFP's were about 200 trillion Btu per month, whereas those arranged through standard futures contracts were only 20 trillion Btu (Figure 3). EFP's are very flexible instruments for arranging gas deliveries. They allow buyers and sellers at different locations to arrange receipt and delivery terms.[9] EFP's require buyers and sellers first to take positions in the futures market before completing a deal in the physical market. Delivery may take place at points other than the Henry Hub, and the delivery price can deviate from the futures contract. EFP's require both parties to set a specific date for completing a contract for the exchange of gas. Yet, parties are able to choose different dates for opening a position on the futures market to gain the best price for their individual objectives.[10] The margin, deposit of moneys or securities by both parties when they open a futures position, also represents a good-faith deposit. EFP's have the further security of being under the scrutiny of the New York Mercantile Exchange (NYMEX) in that NYMEX may take action if it is determined that any default in the delivery was not a consequence of a *force majeure* event.

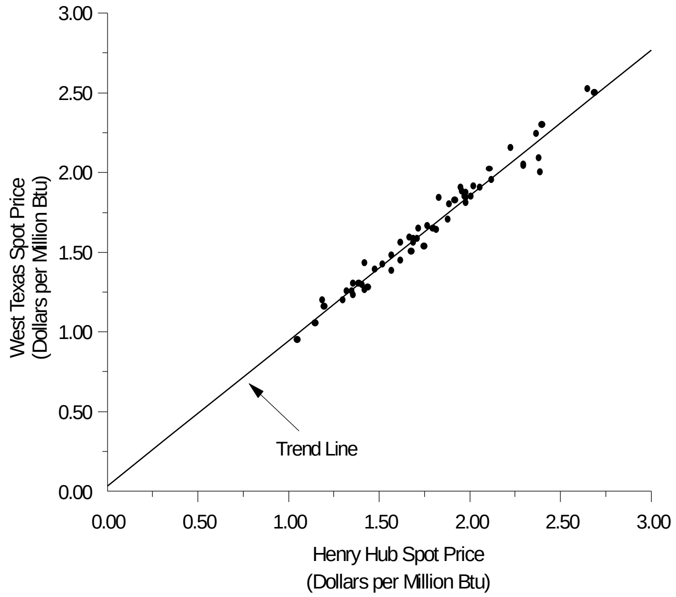
- **Standard deliveries through futures contracts grew by 57 percent in 1994, indicating the reliability of the delivery mechanism associated with the futures contract at the Henry Hub in southern Louisiana (Figure 3).** For each month in 1994, standard deliveries exceeded year-earlier levels. This growth continued into 1995. It should be emphasized again, however, that this delivery mechanism is limited to a very small proportion of total deliveries. Standard futures contracts have very inflexible provisions that place specific requirements on both buyers and sellers as to delivery location, volume, and price.

- **The convergence between futures settlement prices and average bid week prices improved significantly in 1993 and 1994 relative to 1991 and 1992.** Close convergence between the two prices means the futures market is more valuable as a "perfect hedging" tool.[11] Overall, the futures price tended to close below the Henry Hub spot price during bid week in 1991 and 1992. However, the spot price was as likely to rise above the futures price as it was to fall below in 1993 and 1994. More important, the average difference between these two prices was essentially zero for 1993 and 1994, whereas it was $0.042 for 1991 and 1992. A decreasing spread between the spot and futures prices suggests smaller differences in transaction costs between these two markets. It may also imply gains in informational efficiency in the futures market, probably in response to the influx of more diverse and new market participants, and better information about the market.

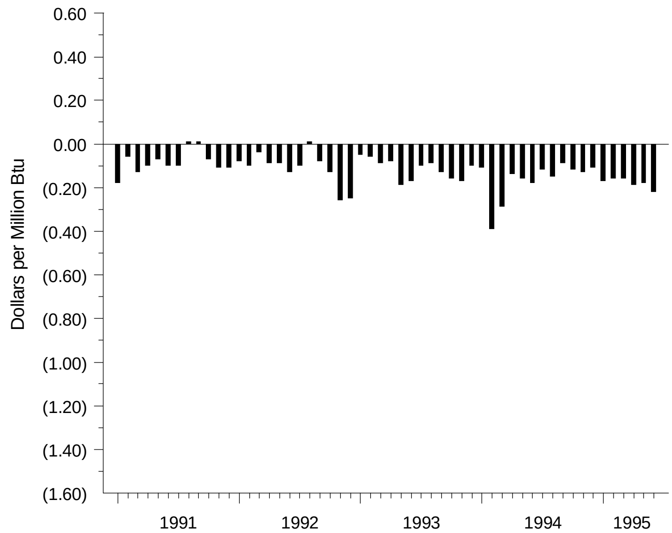
- **The convergence between the futures settlement price and the average spot price for contracts completed during the delivery month also improved significantly in 1993 and 1994 relative to 1991 and 1992.** Close convergence between these price series enhances the value of the futures settlement price as a price index for commodity contracts. As distinct from the bid week period during 1991 and 1992, there was no systematic difference between the futures settlement prices and the spot prices negotiated before and during the delivery month throughout the period. The futures market closed higher than the spot market almost as many times as it closed below it. Although the difference between the two prices can be large, reflecting the great price uncertainty of the market, the average difference declined from approximately $0.05 per million Btu during 1991 and 1992 to $0.02 per million Btu during 1993 and 1994.

Figure 4. Price Differences Between the Henry Hub and Other Spot Markets Have Led to a Second Futures Market

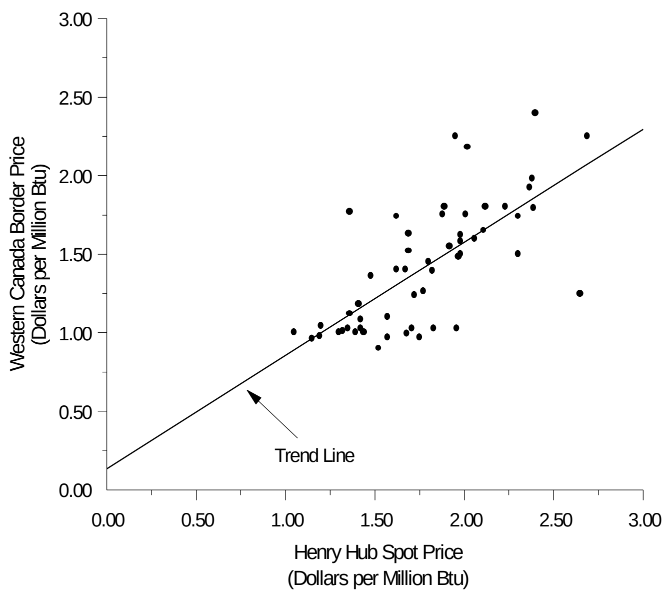
Overall, there is a close relationship between West Texas and Henry Hub spot prices . . .



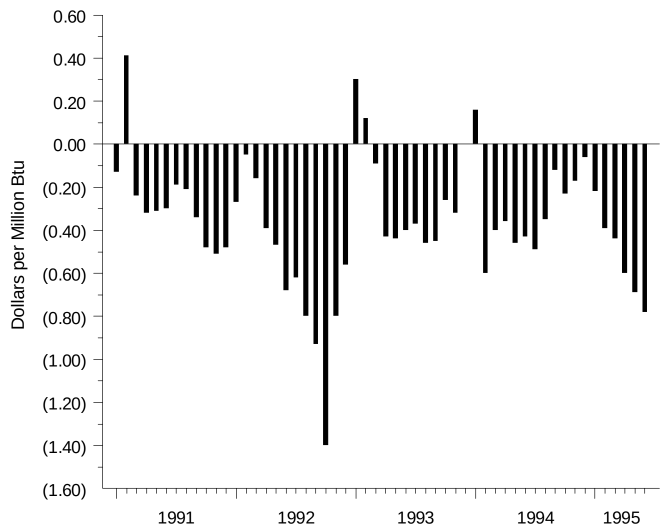
. . . Yet, the difference between West Texas and Henry Hub spot prices has increased



There is much uncertainty in the relationship between Canadian and Henry Hub spot prices



The difference between Canadian and Henry Hub prices has declined, but remains large and variable



Note: The trend line is the result of a least-squares regression of data from 1991 through 1994. The West Texas price is for Valero Transmission L.P. The Canadian price is the Canadian border price for Northwest Pipeline Corp.

Sources: Energy Information Administration, Office of Oil and Gas, derived from: Spot Prices–McGraw Hill, *Inside F.E.R.C.'s Gas Market Report*, various issues.

A Second Futures Market

The Henry Hub futures and spot prices are used to hedge price risk and to index contracts for gas deliveries throughout the United States and Canada. Their use, however, is not without problems in that the difference between the Henry Hub price and the price at some other spot markets can vary greatly. This variability is known as "location basis risk." If the basis risk is small, then the futures contract can be used to hedge price risk effectively throughout the United States. However, for markets in the western part of North America it appears that basis risk is large and increasing. This aspect of western markets has led to development of a second futures market for delivery at the Waha Hub in West Texas.

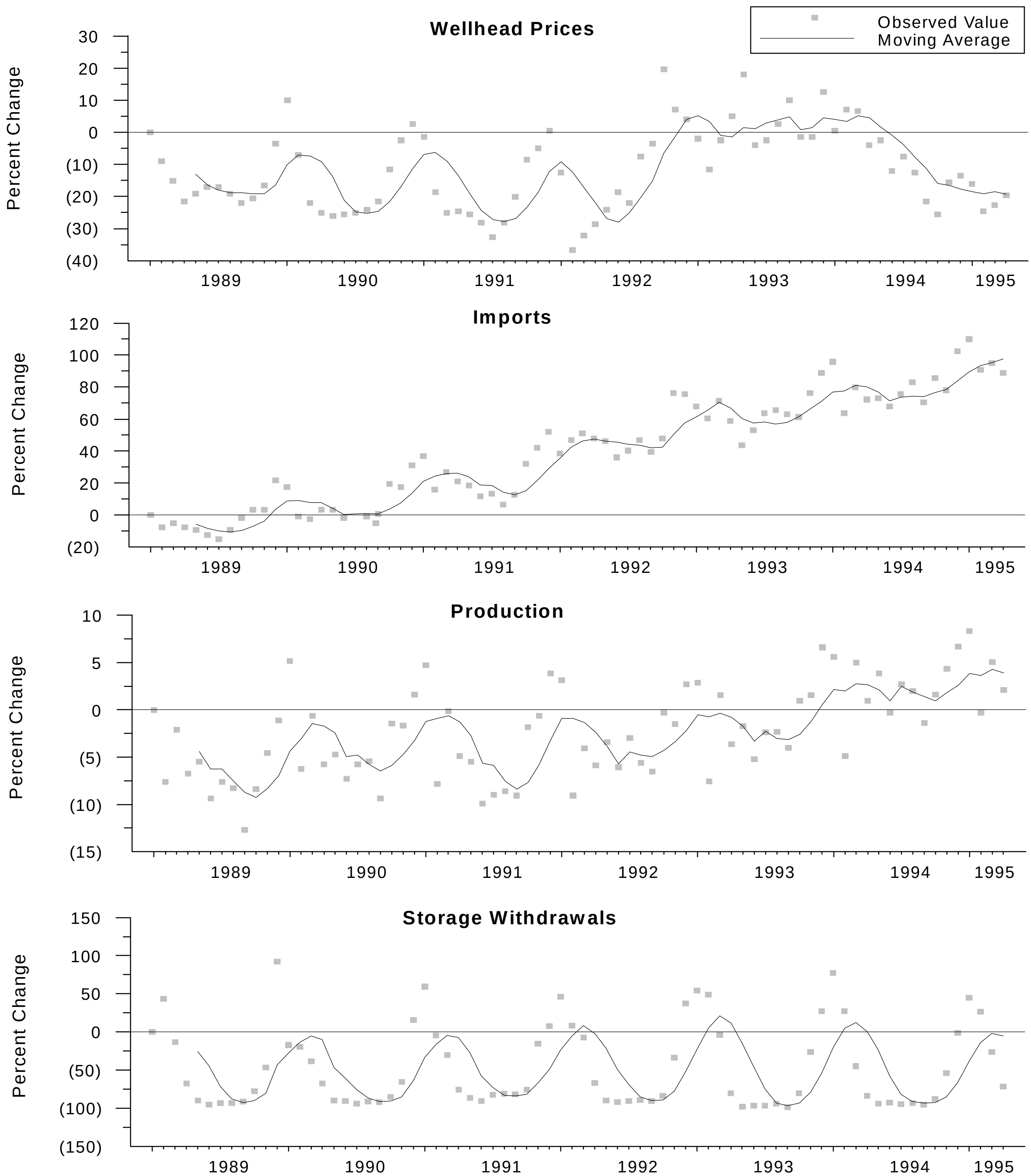
- **The difference between gas prices at the Henry Hub and West Texas spot markets has more than doubled in the past 2 years.** The average price difference increased from $0.085 per million Btu for 1991 and 1992 to $0.180 per million Btu for 1993 and 1994. At first glance the strong relationship between Henry Hub and West Texas prices (Figure 4) suggests that a futures contract for delivery in West Texas is unnecessary. The two series vary together in that high (low) Henry Hub prices are associated with high (low) West Texas prices. Because the difference between the trend line and a point is small relative to the price range, which can be used as a measure of price risk, it would seem that much of the price risk in the West Texas price could be controlled through a Henry Hub futures contract. However, the price risk has become greater during the past 2 years as the average difference in price has not only increased but also become more variable. Because the specific factors that account for these changes are unknown, it is unclear whether the difference is likely to increase or decrease in the future. Thus, it is impossible to account for changes in the size of the difference using the Henry Hub futures contract. For many other commodities, the difference between a price at the futures contract delivery point and at another location is relatively constant and frequently equal to a transportation cost between the two locations. Thus, it is easier to hedge the price risk through a standard futures contract for these commodities.

- **The difference between the price of gas at one location versus another changes over time, which complicates the drawing up of longer term contracts and the hedging of price.** For example, there is a weak relationship between the Henry Hub spot price and the Western Canadian price (Figure 4).[12] This weak relationship is important especially if the difference changes dramatically. For instance, before January 1993, the Canadian price was about $0.40 per million Btu less than the Henry Hub price. However, in January 1993 the Canadian price was $0.30 more than the Henry Hub price. This price difference is explained by relatively cold weather in the western part of Canada and the Northwestern United States when it was relatively warm in the eastern part of North America. Producers who entered into a fixed-price contract indexed to the Henry Hub price less $0.40 in an attempt to control price risk would have received approximately $0.70 per million Btu less than the market price for their gas.[13] Overall, the average difference between the Henry Hub spot price and a Canadian price at the Sumas/Huntington border point into Washington State is not only large but highly variable as measured by the standard deviation.[14]

- **The new futures contract market, supported by the Kansas City Board of Trade (KCBT) for delivery at the Waha Hub in West Texas, began trading on August 1, 1995.** The purpose of this market is to improve price discovery in West Texas, an important producing area, and the western North American markets, and to improve the quality of the hedge available for western markets through a futures contract. The delivery mechanism for the KCBT Western Natural Gas Futures contract is through Valero Transmission Company's Waha Hub in West Texas, which is an interconnection point for four interstate pipelines, six intrastate pipelines, and the Mobil Waha plant.[15] West Texas is considered to be much better connected to western markets than is the Henry Hub. Thus, the expectation is that the combined overall size of the KCBT and NYMEX natural gas futures market will increase.

The development of a second futures contract for natural gas highlights the ability of the market to respond to the dynamics of a changing, less regulated industry.

Figure 5. Wellhead Prices and Related Variables: Some Interesting Changes Since 1989



Notes: Data for 1994 and 1995 are preliminary. The percent changes are calculated from January 1989. The moving average is a 5-month moving average. The scales on the four graphs are different.

Source: Energy Information Administration, Office of Oil and Gas, derived from: *Natural Gas Monthly*, various issues through April 1995.

Changing Market Dynamics

The dynamics of the market have changed dramatically as the industry adjusts to the more flexible and competitive nature of the market with deregulated wellhead prices and the opening of access to the transportation network. Better price signals from the end users to the suppliers and the ability to negotiate contracts and services more freely have resulted in an industry that can focus better on cost containment and inventory management. Together these factors have provided the basis for a different approach to management of wellhead productive capacity and pipeline system and storage operations.

Natural gas wellhead prices, imports, production, and storage withdrawals are related to one another in several important ways. Withdrawals of gas from underground storage and imports of gas from Canada supplement and substitute for gas from domestic production. Over the next several years, the strategic use of storage and imports to smooth production flows throughout the year should continue to result in less seasonal variation in price than that observed in the late 1980's and early 1990's.

- **Wellhead prices have had no obvious winter-summer seasonal pattern for almost 3 years** (Figure 5). The reduction in seasonality is due to several factors. Increased imports, especially during the winter, have helped to levelize production. Thus, fewer less productive wells needed to be brought on line, and fewer existing wells needed to be produced beyond their most efficient level in order to satisfy large shifts in demand during the winter. These changes reduce the upward pressure on increasing prices during the winter. The large swings in the price seen on a month-to-month basis directly reflect the prices needed to clear the market under the current supply and demand conditions. Moreover, the increased deliverability from storage sites and pipeline expansions will also tend to reduce prices in the winter, especially if the growth in deliverability exceeds the growth in demand. Finally, the existence of an active futures market affects the pattern of wellhead prices in a year.[16]

- **Production continues to grow but exhibits less seasonality, with much of the increases in the summer, off-peak months dedicated to storage injections.** Although increased utilization of new technologies such as natural gas air conditioning and vehicles would increase off-peak use of gas, other factors are currently more important. Summer production has been largely dedicated to the injection of gas into storage for later winter use and for incremental demand from electric utilities and industrial cogenerators. Discounted transportation rates during the summer months may also have encouraged large commercial, industrial, and electric utility customers to increase their direct purchases from producers, raising production levels during these months. Overall, increased flexibility in gas purchasing behavior is a factor in the reduction seen in much of the month-to-month variation in production (Figure 5).

- **More intensive use of storage throughout the year is a key factor in the ability of firms to smooth production flows.** Seasonality in withdrawals has been more pronounced in the past several years because of the development of new storage capability and the increased access to storage under Order 636. The increased dependence on withdrawals of natural gas from storage during the winter has reduced the demand for natural gas at the wellhead during periods of stress and hence tended to keep prices down in the winter. As the wellhead price increases in response to the shift in demand, more gas is withdrawn from storage. As the wellhead price declines, more gas is injected into storage to prepare the industry for the next shift in demand. This process tends to smooth prices between weeks and months by shaving the peak from prices when prices start to rise and cushioning the decline in price when price begins to fall. On the other hand, short-term volatility will be sustained by unpredictable shifts in the weather and the industry response to expected changes in market conditions.

- **Imports have traditionally served as a marginal source of gas but are increasingly the mainstay of certain markets.** By early 1995, monthly imports were more than double the level in July 1989 (Figure 5). Although the rate of growth has slowed somewhat since November 1992, imports remained relatively constant throughout 1994 instead of declining in the summer as they had in previous years. Imports are most likely to continue to increase. Some Canadian pipeline companies serving U.S. markets have a backlog of customers seeking firm capacity. This situation provides support for pipeline expansion and, as Canadian producers also seem willing to supply gas at relatively low prices, will continue to place downward pressure on U.S. gas prices.

Chapter 1 Endnotes

1. For the period January 1993 through June 1995, the average value of an annualized price volatility computed for the nearby month futures contract (the contract next to expire) was 42 percent. This compares with a 14-percent volatility for the Standard and Poor's (S&P) 500 stock index. See William Baldwin, "Crash Insurance," *Forbes* (July 31, 1995), pp. 116-119.

2. The price of the nearby contract is used throughout the industry as an indicator of the spot price for natural gas for a delivery month before the spot contract market for a delivery month actually begins. For example, the futures contract for March delivery is the nearby contract during the first 3 weeks of February. During the last week of February, trading in the March futures contract ends and the spot contract market for March delivery begins.

3. The weighted price series is constructed by taking a daily weighted average of the 18 prices associated with the 18 distinct future delivery month contracts trading each day. The weights are the amount of open interest associated with a particular contract relative to the total open interest over all 18 contracts traded on a day.

4. For a technical treatment of the relationship between volatility (as measured by daily variability in prices) and the volume of trade, see John H. Herbert, "Trading Volume, Maturity and Natural Gas Futures Price Volatility" *Energy Economics* (1995), to be published.

5. The Henry Hub in southern Louisiana is the delivery point for the New York Mercantile Exchange (NYMEX) natural gas futures contract. The hub, operated by Sabine Pipe Line Company, is near major producing areas and many pipeline interconnections.

6. The basis risk referred to here is the difference between the daily Henry Hub spot price and the price of gas at another location in the United States.

7. For a discussion of the swaps and options markets, see Energy Information Administration, *Natural Gas 1994: Issues and Trends*, DOE/EIA-0560(94) (Washington, DC, July 1994), Chapter 3.

8. For further discussion of this issue, see John H. Herbert, "The Relation of Monthly Spot to Futures Prices for Natural Gas," *Energy*, 18 (1994), pp. 1119-1124; "The Natural Gas Futures Market - Is It Still Inefficient?" *Energy Exploration and Exploitation*, 12 (1994), pp. 369-380; and "U.S. Natural Gas Markets - How Efficient Are They?" *Energy Policy*, 24 (March 1996), to be published.

9. The buyer and seller can also set the cost of moving the gas from one point to another by entering into a swap arrangement for transportation.

10. For detailed information about EFP's, see Jerry E. Brown and J.C. Whorton, Jr., "Exchange of Futures for Physicals: New Market Opportunities for North America," Occasional Paper 21, International Center for Energy and Economic Development (Boulder, CO, Spring 1993).

11. Convergence means that the futures contract price on the final day of trading equals the spot price for the same delivery month. See Energy Information Administration, *Natural Gas 1994: Issues and Trends*, DOE/EIA-0560(94) (Washington, DC, July 1994), Chapter 3. The articles cited in endnote 8 also discuss the issue of convergence.

12. The relationship is weak relative to the relationship between the Henry Hub and West Texas price. The estimated regression relationships, with the standard errors in parentheses, are as follows:

$$\text{West Texas} = \underset{(0.04)}{0.03} + \underset{(0.02)}{0.91}\ \text{Henry Hub} \qquad R^2 = 0.98$$

$$\text{Western Canada} = \underset{(0.18)}{0.13} + \underset{(0.10)}{0.72}\ \text{Henry Hub} \qquad R^2 = 0.50$$

where R^2 is the coefficient of determination.

13. If a seller had placed a January hedge in the fall to obtain a fixed price for gas that was \$0.40 per million Btu (MMBtu) below the NYMEX futures price, then the seller would have experienced about a \$0.70 per MMBtu loss on this transaction. This is because the relationship between the Canadian and Henry Hub price had changed. The Canadian price was higher than the Henry Hub instead of the other way around as expected. The Canadian price was about \$0.30 per MMBtu higher than the Henry Hub price as it was cold in western Canada but warm in the eastern United States. Based on history, the Canadian price was expected to be about \$0.40 per MMBtu below NYMEX. Thus, if NYMEX was \$1.50 per MMBtu, the seller agreed to sell at \$1.10 per MMBtu. However, the seller could have sold at \$1.80 per MMBtu because the Canadian price was \$0.30 per MMBtu higher

than the NYMEX price at the time. For additional examples of such relationships see John A. Harpole, “Wanted: Opal,” *Natural Gas Focus* (November 1993), pp. 18-20; and Jackie Mitchell, “The Regional Evolution in the Natural Gas Industry: Setting the Stage for the Kansas City Board of Trade Western Natural Gas Futures Contract,” Kansas City Board of Trade (May 2, 1995).

14. The average difference between prices at West Texas, Henry Hub, and several other western locations is of some interest. For the Northern Ventura (NV) and Henry Hub (HB) difference (NV - HB) and the Natural Gas Pipeline Company, Oklahoma (NGPL) and HB difference (NGPL - HB) when compared with the NV and West Texas (WT) difference (NV - WT), and the NGPL and WT difference (NGPL - WT), the average values using the WT price as a basis of comparison are less than the average values using HB price as a basis of comparison. The average value of NGPL - HB is $ -0.14 per MMBtu with a standard deviation of $0.072 per MMBtu, while the average value of NGPL - WT is $-0.02 with a standard deviation of $0.049. The average value of NV - HB is $ -0.13 with a standard deviation of $0.10, while the average value of NV - WT is $ -0.01 with a standard deviation of $0.075. Finally, the average difference between the HB and the Canadian price is $0.35 per MMBtu with a standard deviation of $0.30 per MMBtu while the difference between WT and the Canadian price is less at $0.22 with a standard deviation of $0.29 per MMBtu. The source of the data is McGraw-Hill, Inc., *Inside F.E.R.C.'s Gas Market Report* (New York, NY), various issues.

15. The four interstate pipeline companies are: El Paso, Natural Gas Pipeline, Northern Natural Gas, and Transwestern. The intrastate pipeline companies are: Delhi, Lone Star, Oasis, Teco, Westar, and Valero.

16. Jeffrey Williams, *The Economic Function of Futures Markets* (Cambridge University Press, 1986); and Jeffrey Williams and Brian D. Wright, *Storage and Commodity Markets* (Cambridge University Press, 1991).

2. Natural Gas Supply

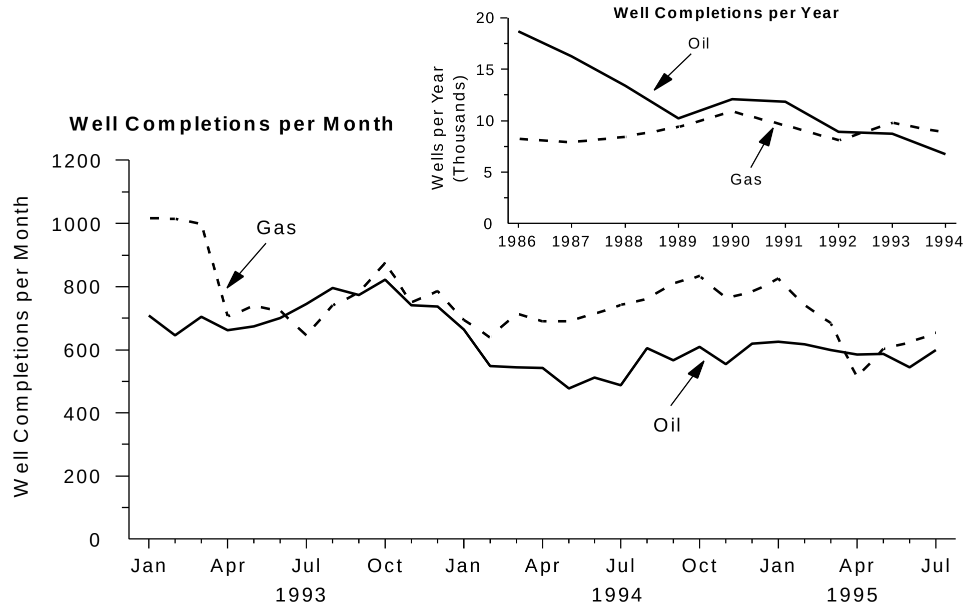
The continuing decline in wellhead gas prices highlights the competitive environment domestic producers are facing—prices at half the level of a decade ago with a volatility that requires careful planning by the industry to manage price risk. The reaction of the industry has been dramatic. Producers have redirected drilling efforts, trimmed costs, reduced the reserve inventory, and continued to increase production. Greater flexibility in contracting arrangements, while providing more options to companies, has added a new dimension of complexity to their operations. Many producers have ties with marketing companies in order to develop their customer base and with storage facilities to manage flow requirements to their customers.

Foreign supplies are a major factor in the U.S. market. The Canadian presence is an increasingly important aspect of the U.S. gas market. Canadian supplies to the United States impose competitive pressure on domestic producers, and the current supply situation in Canada shows potential for expansion despite low prices. Canadian producers are extensively developing current reserves, and recent drilling has hit all-time highs. With only modest growth expected in Canadian demand for natural gas, Canada will continue to seek additional market share in the United States and Mexico. Other foreign sources of natural gas currently contribute little to the domestic market. Liquefied natural gas imports have been limited because of the relatively low gas prices in the United States. Despite its extensive gas resources, Mexico is a net importer of gas. This situation will continue until its gas resources become more fully developed.

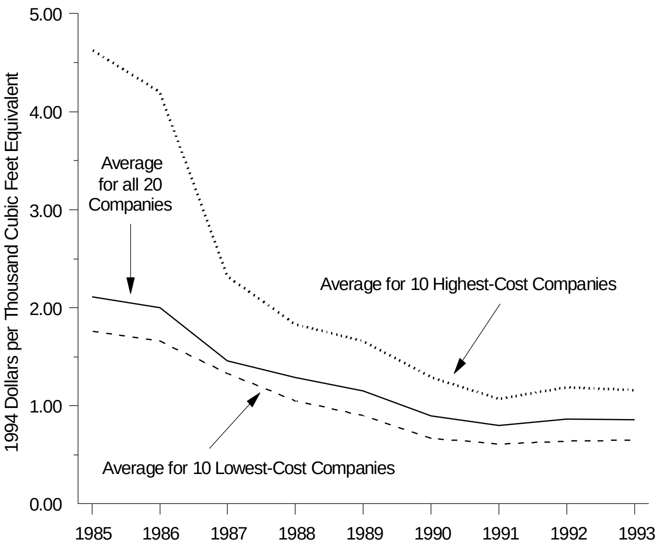
This chapter addresses recent developments in domestic production and import/export markets, providing insights on the extent of the restructuring that has taken place in the industry and on some of the continuing concerns the industry has regarding future supply availability.

Figure 6. Drilling Reflects Improvements in Technology and Efficiency

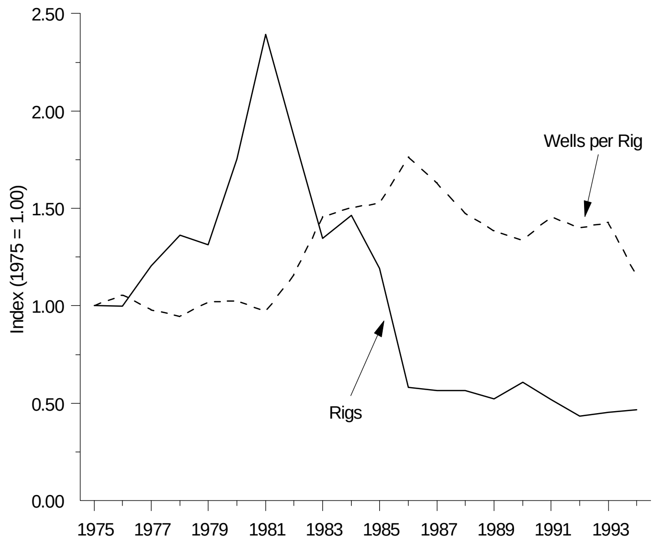
Drilling is directed increasingly toward gas



Onshore finding costs for large oil and gas companies decline



Wells per rig have increased



Note: The companies with the lowest and highest finding costs may be different in each year.

Sources: Energy Information Administration (EIA), Office of Oil and Gas. **Well Completions:** derived from: Well Completion Estimation Procedure (WELCOM). **Finding Costs:** derived from: Form EIA-28 “Financial Reporting System.” **Drilling Productivity Indices:** derived from: Number of Rotary Rigs—*Monthly Energy Review* (June 1995) and Well Completions—WELCOM.

Natural Gas Production and Drilling

The increasing volume of natural gas being produced domestically despite relatively low prices underscores the dramatic changes that have taken place in the industry during the past decade. Domestic production in 1994 continued the upward trend evident since 1986. The production increases reflect the combined benefits of efficiency gains and improved technology. With the decline in wellhead prices over the past decade, firms have been under strong economic pressure to improve operations. Many have improved their exploratory and production performance significantly by lowering costs or increasing productivity.

- **Production in 1994 reached 18.8 trillion cubic feet (Tcf), a 3-percent increase from the level in 1993.** Production in the first 5 months of 1995 totaled 7.9 Tcf, a rise of 1 percent above the level for the comparable period in 1994. Since the low point in 1986, production by 1994 had risen by 2.8 trillion cubic feet to its highest level since 1981. The strength of this upward trend is indicated by the fact that the average daily gas production in each month from January 1993 through May 1995 was higher than that of the corresponding month in the prior year.

- **Gas drilling in 1994 showed a general upward trend during the year, but total well completions were below 1993 levels.** The highest gas wellhead prices in 5 years provided the stimulus for an upturn in drilling in 1993. Although 8,833 gas wells were completed in 1994, the strong gas drilling performance in early 1993 overshadowed 1994 drilling activity. For the first 7 months of 1995, gas well completions were 4,641, a decline of 5 percent and 20 percent, respectively, from comparable periods in 1994 and 1993. Since the beginning of 1993, gas well completions have exceeded oil well completions, with the difference widening in 1994. Gas well completions continue to exceed oil completions in 1995, although the difference has narrowed because of the decline in gas prices. Since 1986, gas well completions have fluctuated within a range of 7,900 to 10,800 without a discernable trend, in contrast to oil completions which have exhibited a long-term decline (Figure 6).

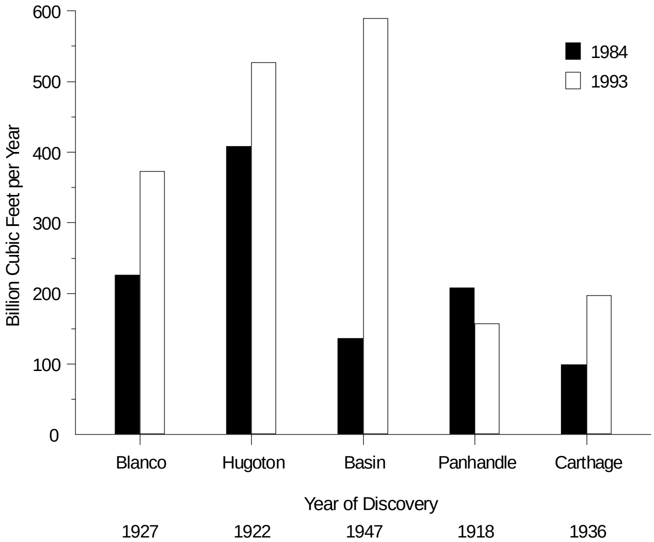
- **Gas well finding rates[1] for the lower 48 States in 1994 exceeded 17 billion cubic feet per exploratory well, more than double the average yield in the early 1980's.** Better exploratory techniques have allowed companies to find larger fields more quickly. New techniques, such as three-dimensional seismic analysis, provide more accurate images of the subsurface. More reliable information allows companies to plan their capital investments with lower risk, enhancing the expected profitability of exploratory drilling. The higher finding rates have served to mitigate any decline in proved gas reserves[2] from that which would have been expected given the lower levels of gas drilling.

- **The 1993 costs of finding and producing onshore natural gas were less than half the costs in 1985.** These comparisons are for the major integrated oil and gas producing companies and the large independent firms included in the Energy Information Administration’s Financial Reporting System (FRS).[3] Increased drilling productivity served to lower the average onshore finding cost[4] by 59 percent to $0.86 per thousand cubic feet (Mcf) equivalent of natural gas in 1993 from $2.11 per Mcf in 1985. The average cost for the highest cost companies in that period declined more than the average for all the companies, from $4.63 per Mcf equivalent in 1985 to $1.16 per Mcf in 1993, a reduction of 75 percent (Figure 6). In addition, many firms became more cost efficient in production, as indicated by the 51-percent decline in average onshore unit production costs for the FRS firms in the lower 48 States between 1985 and 1993. Average production costs for all FRS firms in 1992 and 1993 were no more than $1.00 per Mcf equivalent, with the lowest cost for any FRS firm at $0.48 per Mcf.

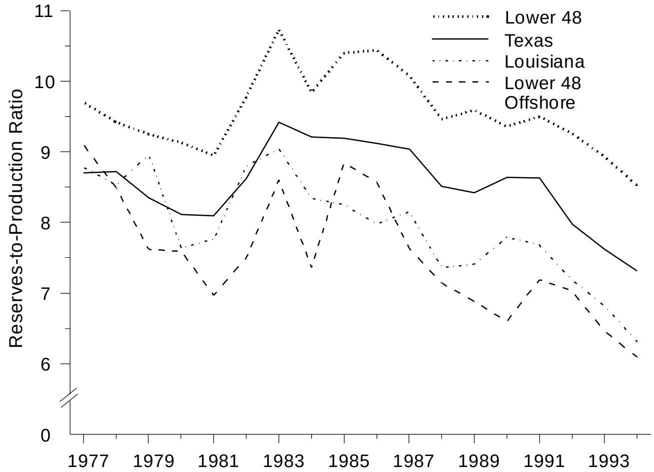
- **Well completions per rig for the past decade have exceeded the level of the early 1980's.** Annual drilling rig productivity[5] remained steady during the period of growing rig use in the late 1970's and early 1980's, ranging from 22 to 24 wells per rig (Figure 6). As the number of rigs in operation declined from the 1981 peak of 3,970 rigs, productivity rose to a high of 41 wells per rig in 1986. The rapid decline in oil and gas prices in 1986 motivated peak rig performance, but the temporary nature of the gain in wells per rig suggests that this level of productivity could not be sustained. Drilling rig productivity has averaged 32 wells per rig during the years since 1988. One factor behind the recent decline is the increased emphasis on horizontal and other advanced drilling and completion techniques that often require the rig to be onsite longer. The decline in wells per rig has been offset by increased productivity at the wellhead. For example, while horizontal wells take longer to drill, they provide access to a much greater area of the reservoir, which provides greater well productivity.

Figure 7. Production Practices Improve

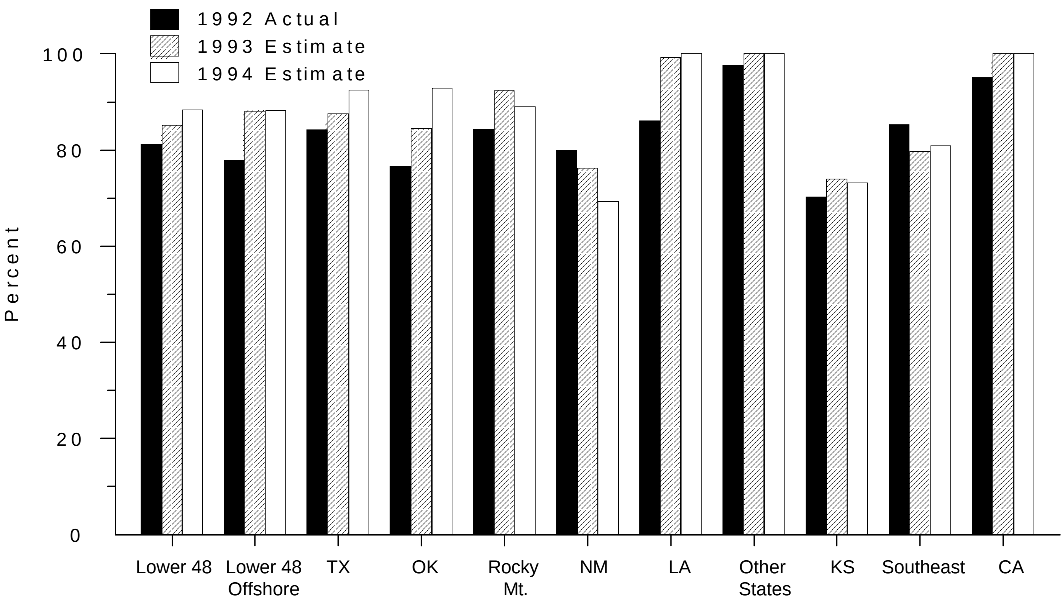
Production has increased from most of the 5 largest fields



Reserves-to-production ratios have declined since 1985



Productive capacity utilization rates show some spare capacity



Percent of 1992 Production

	Lower 48	Lower 48 Offshore	TX	OK	Rocky Mt.	NM	LA	Other States	KS	Southeast	CA
By Region	100.0	28.6	26.2	10.2	7.9	7.7	7.6	4.1	3.8	2.6	1.4
Cumulative	--	28.6	54.8	65.0	72.9	80.5	88.1	92.2	96.0	98.6	100.0

Sources: Energy Information Administration. **Reserves-to-Production Ratios**: Office of Oil and Gas, derived from: **Reserves and Production**—*Advance Summary: U.S. Crude Oil, Natural Gas, and Natural Gas Liquids Reserves: 1994 Annual Report* (August 1995). **Productive Capacity Utilization Rates:** *Natural Gas Productive Capacity for the Lower 48 States: 1980 Through 1995* (July 1994).

Natural Gas Inventories

Proved reserves are the inventory from which production is drawn. As the industry faces increased pressure to contain costs, inventory levels constitute one area that has come under increasing scrutiny. As recently as January 1987, more than 30 percent of the Nation's natural gas productive capacity lay idle, clearly more than the industry's operational needs. Idle capacity in January 1995 is estimated at a more efficient 12 percent. Monthly productive capacity should be able to meet normal production demands through 1995 in the lower 48 States.

Nationally, gas production rose by 15 percent between 1985 and 1994, while real wellhead prices and proved reserves declined by 45 and 3 percent, respectively.[6] This demonstrated ability to produce more gas from fewer reserves despite lower real prices provides strong evidence that a combination of improved efficiency and technology has fundamentally altered the gas supply process.

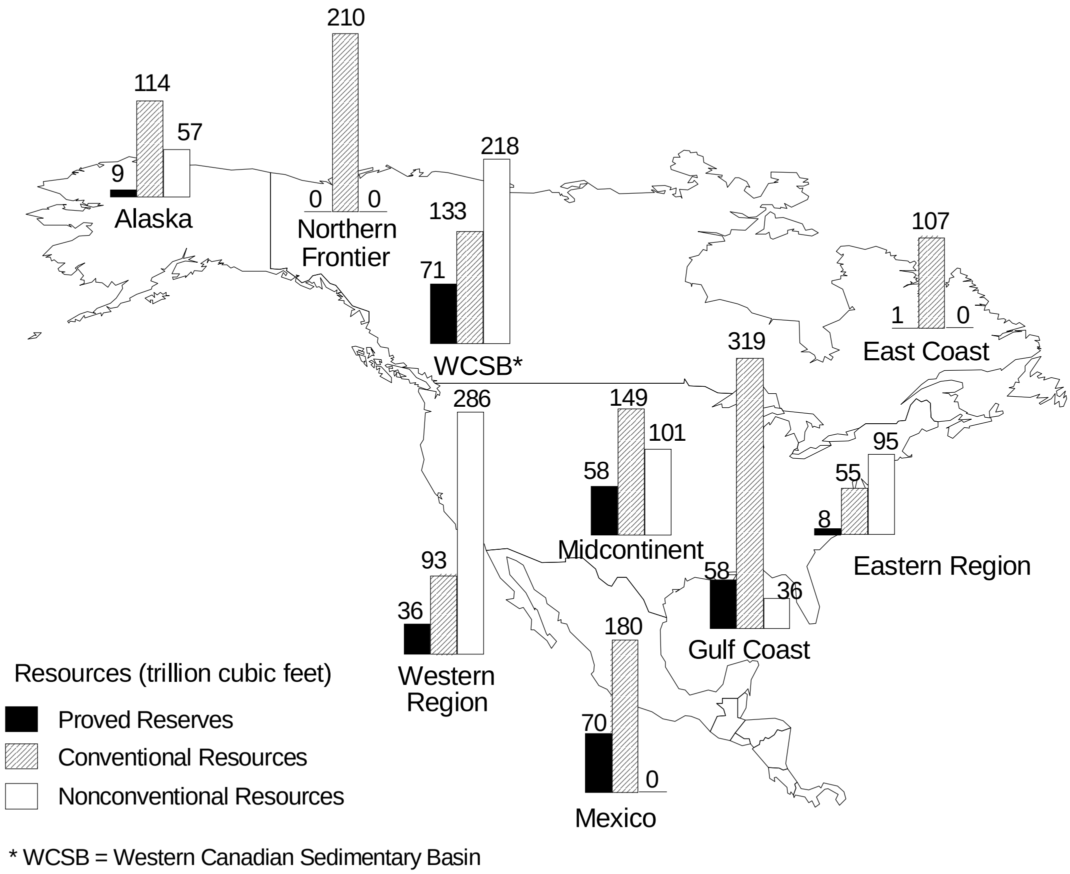
- **Some of the Nation's oldest and largest fields are showing increased production rather then declining as typically expected.** The Nation's largest gas field,[7] Hugoton, was discovered in 1922, so production would be expected to be in decline. Instead, production from Hugoton and three of the other four largest gas fields in the lower 48 States has increased since 1984 (Figure 7). Estimated ultimate recovery from these five fields rose 22 trillion cubic feet between 1984 and 1993. The increases can be attributed at least partly to production efficiency gains brought about by the relaxation of State regulations, such as those affecting well spacing. For example, recent changes in State prorationing rules are expected to increase gas production from the Hugoton Field by approximately 10 to 15 percent.[8] The other important factor is application of new technology. For example, the application of three-dimensional (3-D) seismic techniques in the Gulf of Mexico by ANR Production Company increased production from 3.5 million cubic feet (MMcf) per day to more than 30 MMcf per day.[9]

- **The reserves-to-production ratio (R/P) for the lower 48 States has declined gradually, from 10.4 in 1986 to 8.5 in 1994.** This trend is seen in both the onshore and offshore producing areas of the lower 48 States (Figure 7). The R/P ratio is an indirect and, in light of the extensive changes affecting the industry, an increasingly questionable indicator of supply security. While the lower R/P ratio has raised concern by some analysts because it is perceived as an indicator of dwindling productive capability, the movement to lower inventory margins is also an efficiency improvement that reduces unit supply costs. The technological successes that have resulted in the lower R/P ratios also serve to improve supply potential. For example, 3-D seismic technology has progressed to the next level: four-dimensional (4-D), or "time-lapse seismic monitoring." The 4-D techniques track the movement of fluids to identify reservoir abnormalities, monitor migration of oil/water contacts, and locate bypassed hydrocarbons.[10] Such technological improvements are expected to maintain and enhance the production performance of the industry.

- **Substantial productive capacity remains in the lower 48 States, but capacity utilization is estimated to be close to the maximum in some States.** Analysis of the production capacity of wells in the lower 48 States indicates that monthly productive capacity should be sufficient to meet expected demand at present.[11] The overall surplus, however, obscures the high capacity utilization in certain areas such as Louisiana, California, and a group of 18 smaller producing States.[12] Of these, Louisiana is by far the largest producer, accounting for 7.6 percent of lower 48 production in 1992, exceeding California and the other 18 combined. The diminished productive surplus could result in disruptions of localized markets under high demand conditions, unless alternate supplies are available on the interstate network.

Firms producing natural gas have made significant changes during the past decade—improving discovery and recovery technologies, and altering their business operations in response to the institutional changes affecting their industry. In light of the large endowment of remaining recoverable natural gas resources in North America, natural gas is expected to continue, if not expand, its key role in U.S. energy markets.

Figure 8. Technically Recoverable Gas Resources in North America Comprise Almost 2,500 Trillion Cubic Feet



Notes: Technically recoverable resources are those volumes producible with current recovery technology and efficiency but without reference to economic viability. Conventional and nonconventional recoverable estimates incoporate technology advances through 2010, except for Mexico for which advanced estimates are not available.

Source: National Petroleum Council, *The Potential for Natural Gas in the United States: Source and Supply* (December 1992).

U.S. Natural Gas Supply Sources

U.S. natural gas markets have access to diverse sources of natural gas supply, domestic as well as foreign. The infrastructure of the United States includes extensive facilities for importing natural gas via pipeline or via tanker in the form of liquefied natural gas (LNG). Development of the natural gas transmission and distribution system across North America has achieved a fair degree of physical integration that benefits both producers and consumers, and foreign supplies have served as an important source of gas to U.S. markets for many decades. Each of the three countries of North America enjoys a substantial endowment of recoverable natural gas resources. Continued trade in North American gas is expected to flourish in light of the almost 2,500 trillion cubic feet (Tcf) estimated to remain as technically recoverable natural gas resources (Figure 8).

- **The United States, the second largest producer of natural gas in the world, has an estimated 1,475 Tcf of remaining recoverable gas resources.**[13] This resource volume is the equivalent of roughly 78 years of production at the 1994 level, although not all of this gas is expected to be economically recoverable. According to a recent National Petroleum Council (NPC) study, 60 percent of the remaining technically recoverable resources in the lower 48 States (776 of 1,295 Tcf) is expected to be producible by conventional recovery techniques. A key finding of that and similar studies is that a large share of remaining recoverable resources is located in fields that are already producing. The NPC analysis estimates that almost 47 percent of the conventionally recoverable resources (363 of 776 Tcf) are located in currently known fields, but have not yet been developed as proved reserves.

- **Canada has 740 Tcf of recoverable resources, with the Western Canadian Sedimentary Basin (WCSB) being the key geographic area.** Canadian gas recovery and marketing issues are influenced by the geographic distribution of both developed and undeveloped Canadian resources. The WCSB (primarily in the provinces of British Columbia, Alberta, and Saskatchewan) has 422 Tcf, which is 57 percent of the total technically recoverable volume. The WCSB is also the major gas-producing area in Canada, with more than 99 percent of Canadian production and 85 percent of reserves in 1993. More than half the recoverable gas in the WCSB includes gas in low-permeability formations such as coalbed methane.

- **The Canadian frontier areas have over 40 percent of Canadian remaining recoverable resources, but exploitation of this resource is not expected in the near future.** Estimates of technically recoverable gas resources in Canada show that 318 Tcf are located in the Northern Frontier and East Coast regions. These frontier regions lack the developed infrastructure that is essential for marketing gas. Recent relatively low Canadian wellhead gas prices have severely reduced interest in developing gas resources in the Canadian Arctic, as evidenced by the poor response in 1994 to a request for nominations in this area.[14] The Sable Island Gas Project (offshore East Canada) is proceeding, but initial production is not scheduled until November 1999.[15] Thus, the dominance of the WCSB in Canadian gas supply is expected to continue for years to come.

- **Mexico, with 70 Tcf in proved reserves and an extremely low extraction rate, has the greatest potential for production growth in North America.** Mexico has 250 Tcf of recoverable gas resources with 28 percent of this categorized as proved reserves. This quantity of proved reserves is comparable to that of Canada, but Mexico produces only about one-fourth as much. Even if the 27 Tcf of proved reserves in the Chicontepec basin are removed from consideration because of the poor geologic characteristics, Mexico still has a reserves-to-production ratio in excess of 30, compared with 8.5 and 17.0[16] for the lower 48 States and Canada, respectively.

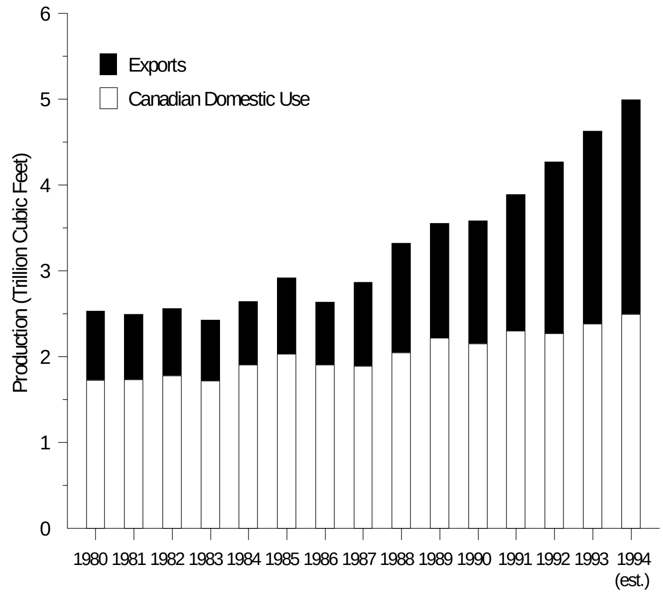
- **The four LNG facilities in the United States can provide access to global gas reserves, which exceeded 4,800 Tcf as of January 31, 1993.**[17] Much of the gas worldwide is expected to be marketed by pipeline sales. However, a number of countries with large gas resource volumes have such limited consumption or other marketing possibilities that LNG trade is the most economically viable option. Growth potential for worldwide LNG trade is thought to be substantial, but relatively high transportation and processing costs have limited U.S. LNG imports to date. Only 51 billion cubic feet of LNG was imported into the two operating LNG terminals in 1994. The limited markets for LNG imports have led the owners of two inactive LNG facilities to pursue a strategy of reopening as natural gas storage projects, with import activity merely a possibility for the future.

The major natural gas trading partner of the United States will continue to be Canada, which has the productive capacity and the resource potential to serve as a key supply source for many years.

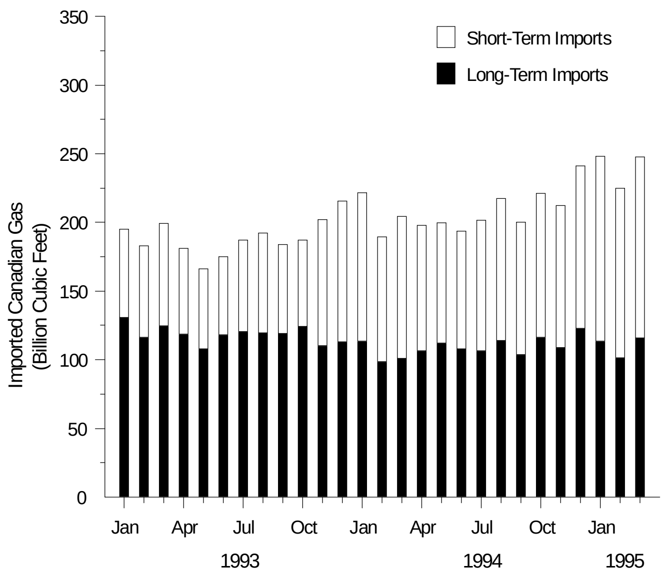
Figure 9. Canada's Role in the U.S. Gas Market Continues to Grow

Canadian gas well completions imply production growth

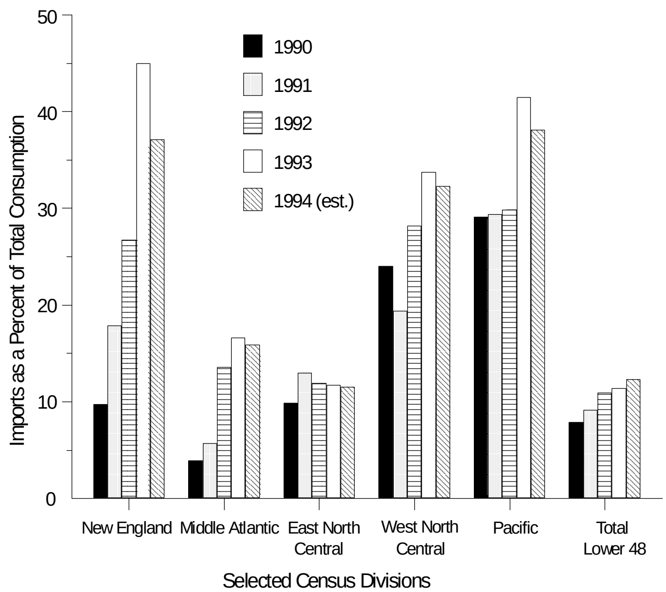
A significant part of Canadian production is exported



Imports from Canada are growing and shifting to short-term contracts



Some U.S. areas rely heavily on Canadian gas



Sources: **Canadian Gas Well Completions, Production, and Exports:** Canadian Association of Petroleum Producers, *Canadian Association of Petroleum Producers (CAPP) Statistical Handbook* (July 1994), with additional telephone contacts. **Imports and Percent of Total Consumption:** Energy Information Administration, Office of Oil and Gas, derived from: *Natural Gas Monthly* (August 1995), *Natural Gas Annual 1993* (October 1994), and import and export data from U.S. Department of Energy, Office of Fossil Energy.

Canadian Supply and Its Role in the U.S. Market

The recent upward trend in Canadian gas well completions contributed to Canada's supply growth in 1994 and implies continued growth in the near term. As has been the case for the past 14 years, much of this growth went to exports (Figure 9). U.S. pipeline imports of Canadian gas in 1994 were higher than in 1993 for every month, and for the year grew by more than 13 percent to an all-time high of 2.6 trillion cubic feet. The growth has continued during the first half of 1995, as preliminary data show that Canadian gas imports are over 8 percent greater than for the same period in 1994.

A major portion of near-term Canadian supply growth continues to be exported, because growth in natural gas consumption within Canada has been and is expected to remain modest. The proportion of Canadian production destined for export to the United States reached 50 percent in 1994. However, imports from Canada are near the upper limit of the existing pipelines' capacity to transport gas into the United States. Capacity utilization on exporting pipelines was 82 percent from November 1993 through October 1994, with utilization rates on lines into the Northeast and Midwest Census regions more than 90 percent.[18] Only Pacific Gas Transmission's (PGT) recently activated expansion line has significant available capacity into the United States, hence the intense interest of Canadians in the outcome of PGT's pending rate case.[19] In the meantime, several pipeline construction projects to increase cross-border capacity are planned or underway.[20] If all projects announced through the end of 1994 were completed as proposed, capacity would increase by about 1.5 billion cubic feet per day by 1997, an increase of 15 percent from the level in 1994.

- **Gas well completions in Canada have quintupled since 1992, indicating that Canada will remain a major supplier to the United States for some time.** Completions in 1994 were 5,369, a new record far exceeding the previous peak of 4,472 in 1980. This increase can be attributed to gas wellhead prices, which in Canadian dollars have improved since 1992, even though the same prices in U.S. dollars have remained low or fallen slightly.

- **Canadian production has increased despite gradual declines in proved reserves.** The increase occurred because of more intense field development and resulted in a substantial decline in the reserves-to-production (R/P) ratios. The R/P ratio for the Western Canadian Sedimentary Basin (WCSB) declined from 29.2 in 1983 to 14.6 by 1993. The U.S. experience suggests that additional production can be gained by exploiting remaining reserves even more intensively.

- **For the eighth straight year, imported Canadian gas increased its share of the U.S. market, with increases in five of the nine Census Divisions in 1994.** The greatest growth occurred in the Pacific Division, where Canadian gas sales increased by 31 percent, from 732 billion cubic feet (Bcf) to 958 Bcf.[21] The Pacific Division continues to be the single largest market area in the country for Canadian gas, consuming more than 38 percent of total gas imported from Canada in 1994. The New England, Middle Atlantic, East North Central, and West North Central Divisions (Figure 9) also have come to rely heavily on Canadian gas. In 1994, the Canadian gas share of total consumption in these areas ranged from 12 to 37 percent; in 1993, it reached 45 percent in the New England Division.

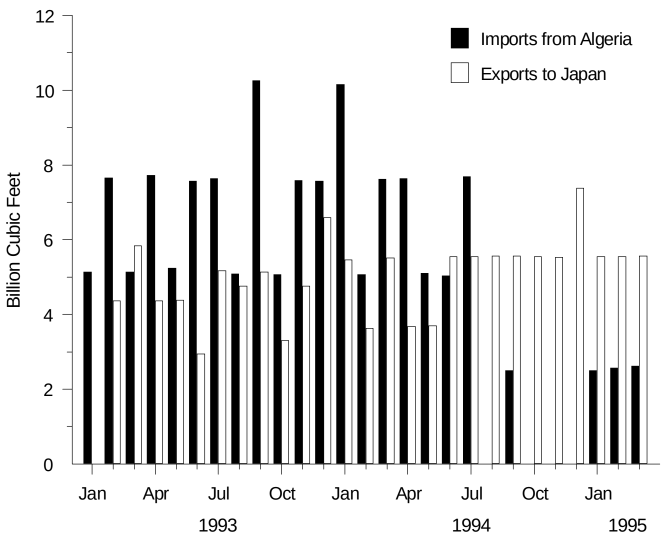
- **Short-term imports into California now far exceed long-term imports.** Short-term imports (under agreements of 2 years or less) increased from 101 Bcf in 1993 to 492 Bcf in 1994, while long-term imports (arrangements for longer than 2 years) declined from 364 Bcf to 160 Bcf.[22] Two key factors prompting this shift were the termination of a major long-term contract involving key Canadian and California players, and the opening of PGT's expansion pipeline from Canada to northern California, both on November 1, 1993.[23] Short-term import agreements are preferred because prices adjust more frequently, and their increased availability beginning in November of 1993 led to increased sales.

- **Revenues to Canadian producers in Canadian dollars have actually increased, despite a fall in the annual average price of Canadian gas in 1994 to an all-time low of US$1.83 per thousand cubic feet.**[24] Increased revenues are due partly to increased sales and partly to the Canadian dollar's devaluation in 1994 of 5.9 percent versus the U.S. dollar, to US$0.74.[25] Natural Resources Canada has estimated that each US$0.01 decline in the value of the Canadian dollar translates into an approximate $34 million increase in Canadian dollar revenues.[26]

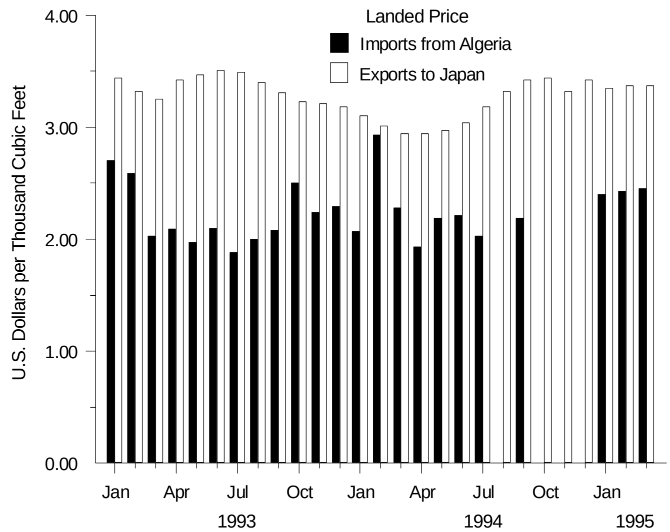
Canada's place as the most significant external supplier of natural gas to the United States seems secure for years to come. On the other hand, the role that Mexico and liquefied natural gas will play in the North American market over time is considerably more uncertain.

Figure 10. LNG and Mexican Trade Complete the U.S. Supply Picture

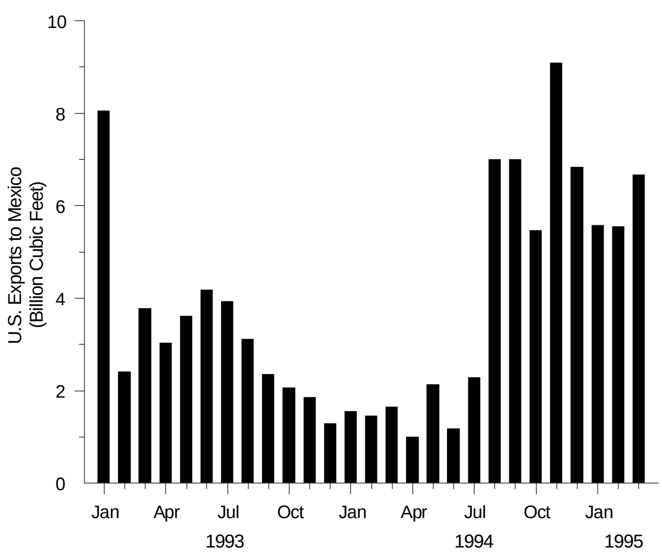
LNG exports remain steady while imports are curtailed

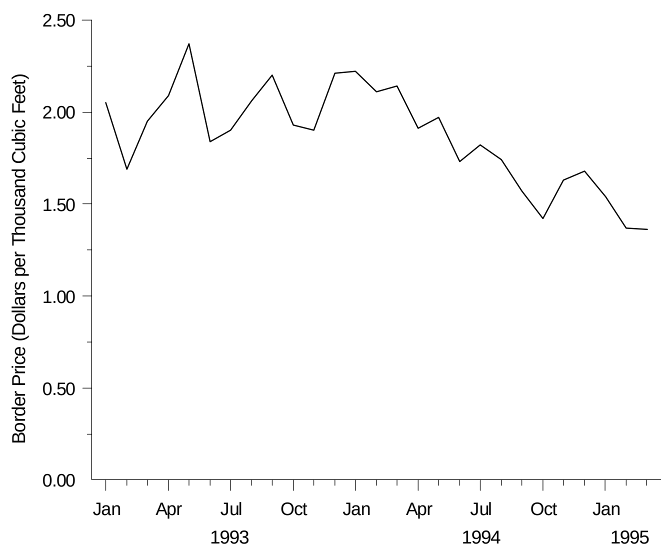


LNG is more highly valued in Japanese markets



U.S. price reductions restore sales to Mexico





LNG = Liquefied natural gas.
Source: Energy Information Administration, *Natural Gas Monthly* (August 1995).

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Recent LNG and Mexican Market Activities

Two additional sources of supply for the United States include imports of liquefied natural gas (LNG) and pipeline imports from Mexico. Since 1970, LNG imports have contributed to the domestic market both as a source of gas from nonadjacent foreign countries and as a source of peakshaving supply.[27] Currently only two of the four LNG import facilities are in operation, because of the relatively low gas prices in the United States. Mexico has the potential for becoming a net exporter of gas, but the lack of development of its producing regions makes it likely to remain a net importer of gas from the United States.

- **LNG imports were on track to match or exceed 1993 levels when they were cut back for an extended period starting in the fall of 1994.** Sonatrach (Algeria), currently the sole source of U.S. LNG imports, undertook a major renovation of its liquefaction plants during the year. As a result, LNG imports were down by 38 percent to 51 billion cubic feet (Bcf) in 1994. At the end of the first quarter 1995, LNG imports were only one-third of year-earlier levels. Reduced shipments likely will continue into 1996, when the renovation is scheduled for completion. Future U.S. LNG imports are expected to include gas from projects that are currently in development in Trinidad and Venezuela.

- **The prices paid for LNG imports averaged $2.20 and $2.28 per thousand cubic feet (Mcf) in 1993 and 1994, respectively, exceeding the average wellhead and pipeline import prices in the same years.** This price differential stems from the locational advantage of LNG import terminals, which are closer to major consumption centers on the East Coast than are the major domestic producing fields.

- **The Cove Point facility in Maryland is to reopen in late 1995 as an LNG storage facility for domestic gas, which is intended for use in peakshaving.** About $55 million is being invested to reopen the facility for this purpose.[28] The operator, Columbia LNG Corp., will continue to seek customers for LNG imports as originally intended for this project. Cove Point was designed with a send-out capability of 1.2 Bcf per day, although deliverability from storage is expected to be one-fourth of that rate. A similar peakshaving project also has been announced for the Elba Island, Georgia facility, which would open by November 1997.[29]

- **LNG continues to be exported from Alaska to Japan, reaching a new high of 63 Bcf in 1994, an increase of nearly 12 percent from the 1993 level.** The increase stems from the commissioning of larger tankers in 1993 and a renegotiated purchase agreement with the Japanese customers. The 1993 and 1994 prices paid for LNG exports ($3.34 and $3.18 per Mcf, respectively) reflect the relatively high value of this gas in Japanese markets.

- **Mexico is the tenth largest natural gas producer in the world,[30] with 1994 production of 1.3 Tcf, yet it is a net importer of natural gas.** Growing border prices through 1993 into 1994 resulted in declining Mexican imports of U.S. gas (Figure 10). After peaking at 96 Bcf in 1992, Mexican imports fell to 40 Bcf in 1993, a drop of 59 percent.[31] However, this falloff appears to be temporary. Price declines during 1994 led to a recovery in Mexican receipts of U.S. gas in late 1994, reaching 47 Bcf. Mexican imports during 1995 have been at least 27 percent higher than during the same period in either of the 2 previous years.

- **The longer term outlook for the Mexican natural gas industry depends on key economic and institutional changes, many of which extend beyond the industry itself.** Mexico has sufficient gas resources to become a net exporter, but is constrained by the lack of a gas infrastructure. The devaluation of the peso in late 1994, while causing a shock to the economy, may ultimately have a limited impact on the Mexican natural gas industry as investment in physical capital by foreign investors appears to be continuing. Legislation passed by the Mexican Senate on April 29, 1995, allows private investment in some aspects of the Mexican natural gas industry.[32] These initiatives already have led to U.S. involvement in a number of projects to develop regional pipelines and local distribution companies along with gas-fired power plants in Mexico.[33]

Mexico will continue as an important U.S. trading partner either as a consumer or producer of gas. LNG is expected to remain a locally significant element in the U.S. natural gas supply outlook. Domestic markets are expected to expand, which will provide opportunities for both domestic and foreign suppliers. The Energy Information Administration's *Annual Energy Outlook 1995* projects incremental consumption of 4.4 Tcf in the United States between 1993 and 2010.[34] Domestic and foreign producers share in this expansion, with domestic production capturing more than 60 percent of the incremental market. In this outlook and those of other agencies, the abundance of overall supplies allows market growth without substantial price increases.

Chapter 2 Endnotes

1. The exploratory finding rate is calculated as discoveries (additional reserves reported as new field discoveries, extensions, and new reservoir discoveries in old fields) divided by exploratory well completions. The numerator and denominator terms are moving 3-year sums—the current observation plus the lagged values.

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

3. The Financial Reporting System (FRS) companies are 25 major U.S. energy companies that are required to report financial and operating developments annually to the Energy Information Administration on Form EIA-28, "Financial Reporting System," pursuant to Section 205(h) of the Department of Energy Organization Act.

4. Finding costs are measured as a 5-year moving average of exploration and development expenditures, excluding expenditures on proved acreage, divided by reserve additions, excluding reserve purchases. Unit costs are for oil and gas combined. Barrels of oil are converted to thousand cubic foot gas equivalents by use of assumed heat content factors: 5.8 million Btu per barrel of oil and 1.03 million Btu per thousand cubic feet of gas.

5. Drilling productivity is measured as the ratio of wells completed during the year divided by the rotary rigs in operation in that year.

6. Natural gas reserves in 1984 have been adjusted to account for the subsequent 24.6 trillion cubic feet reduction in North Slope reserves in 1988.

7. Relative size in this context is established on the basis of 1992 production.

8. "Kansas orders Hugoton proration changes," *Oil and Gas Journal* (February 14, 1993), p. 96.

9. "3D helps rejuvenate old gulf gas field," *Oil and Gas Journal* (January 2, 1995), p. 28.

10. "4D seismic helps track drainage, pressure compartmentalization," *Oil and Gas Journal* (March 27, 1995), pp. 55-58.

11. Energy Information Administration, *Natural Gas Productive Capacity for the Lower 48 States 1980 through 1995*, DOE/EIA-0542(95) (Washington, DC, July 1994).

12. The group of 18 States analyzed as a single region in the cited report are: Arizona, Florida, Illinois, Indiana, Kentucky, Maryland, Michigan, Missouri, Nebraska, Nevada, New York, Ohio, Oregon, Pennsylvania, South Dakota, Tennessee, Virginia, and West Virginia.

13. The recoverable resource estimates for the United States, Canada, and Mexico are from the National Petroleum Council report, *The Potential for Natural Gas in the United States* (December 1992). A more recent assessment by the U.S. Geological Survey provides an updated, but less geographically comprehensive, set of estimates for the United States. Findings in both reports differ in the details but are consistent overall.

14. "Drillers Pass Up Canadian Arctic Until Prices Rise," *Platt's Oilgram News*, Vol. 72, No. 8 (January 12, 1994), p. 2.

15. "Sable Island Gas Project Reported on Track," *Gas Daily* (June 19, 1995).

16. The geology of Canada is expected to yield produced gas at a much faster rate than that corresponding to a reserves-to-production ratio (R/P) of 17. The present low production rate may be attributed primarily to institutional factors that required relatively high R/P ratios in order to establish that gas for export was surplus to foreseeable Canadian requirements. The National Energy Board in 1987 adopted the "Market-Based Procedure" as the surplus determination procedure for export authorization. After adoption of this less restrictive procedure, the R/P ratio declined by roughly half, and this trend is expected to continue.

17. Energy Information Administration, *International Energy Annual*, DOE/EIA-0219(92) (Washington, DC, January 1994), Table 36.

18. Natural Resources Canada, Natural Gas Division, *Canadian Natural Gas Exports Evaluation and Outlook* (March 1995), p. 13.

19. Currently, nearly one-quarter of Canadian natural gas exports leave the country via Pacific Gas Transmission (PGT) for markets in California and the Pacific Northwest, and much if not most of the available capacity into these areas is on the PGT expansion line. PGT's rate filing in February 1994 requested authorization from FERC to implement rolled-in rates on its system immediately, stating that it is an integrated system in which pre-expansion and expansion shippers receive identical services to the same market destination. Currently, incremental rates are being charged pending the outcome of the case; the differential between rates for pre-expansion and expansion shippers is significant: about US$0.24 per thousand cubic feet (Mcf) vs. US$0.43 per Mcf, respectively. (The rolled-in rate is estimated to be about US$0.35 per Mcf.) On March 30, 1994, FERC rejected PGT's application and set the issue for a traditional rate case proceeding. The ongoing uncertainty concerning future rates on PGT has inhibited the formulation of long-term import arrangements. On June 8, 1995, FERC issued an order approving a partial settlement, offered by PGT, that contains a rate mitigation clause applicable to five local distribution companies (LDC's) in the Pacific Northwest. This clause provides that, if rolled-in rates are approved for PGT, these companies will be shielded from significant rate increases through December 31, 2004. Conversely, the settlement agreement provides for a surcharge on expansion shippers to make up the lost revenue that would have been collected from these LDC's under rolled-in rates. Hearings on the case were recently reopened, however, and it is not known at this time what effect this development will have on the schedule or outcome of PGT's rate case.

20. In Canada, expansions to the TransCanada Pipeline system are planned to serve markets in the U.S. Northeast, and both the Canadian and U.S. portions of Northern Border pipeline are to be expanded to enhance service to Midwest markets. Proposed or planned expansions in the United States include: Portland and Mayflower projects in the Northeast, an expansion of Northwest Pipeline to connect with the Trailblazer project into the mid-continent area, and the Altamont, Pacific Gas Transmission expansion, and Tuscarora lines in the Mountain and Pacific Census Divisions. For further details, see the section "Future Pipeline Expansions" in Chapter 4.

21. U.S. Department of Energy, Office of Fossil Energy, *Natural Gas Imports and Exports Fourth Quarter Report 1994* (Washington, DC, 1994), Figure 2, p. 5.

22. U.S. Department of Energy, *Natural Gas Imports and Exports Fourth Quarter Report 1994*, p. 7.

23. The contract termination resolved a controversial situation arising out of the initiation of capacity release on Pacific Gas Transmission's (PGT) pipeline system, mandated by the California Public Utility Commission in 1991. In response to complaints about the effects of capacity release, the Canadian National Energy Board had curtailed short-term, and lower priced, imports on PGT to protect the interests of certain Canadian producers.

24. Historic prices converted to 1994 dollars.

25. Natural Resources Canada, Natural Gas Division, *Canadian Natural Gas Exports: Evaluation and Outlook* (March 1995), p. 12.

26. Natural Resources Canada, *Canadian Natural Gas Exports: Evaluation and Outlook* (March 1995), p. 12.

27. Peakshaving supply is "fuel gas for distribution systems from an auxiliary source (of limited supply, higher cost) during periods of maximum demand when the primary source is not adequate, e.g., propane, LNG." ("Natural Gas Glossary," *Natural Gas Intelligence*, Revised April 1994.) According to Craig Taylor in the article, "LNG for Peakshaving," *The LNG Observer*, Vol. IV, No. 4 (Winter 93/94), p. 17: Peakshaving "...cuts demand for gas on the coldest days of the year."

28. "Cove Point LNG Encouraged by Winter," *Platt's Oilgram News*, Vol. 72, No. 92 (May 12, 1994).

29. Foster Associates, Inc., *Foster Report*, No. 2028 (May 4, 1995), p. 22.

30. Energy Information Administration, *International Energy Annual*, DOE/EIA-0219(92) (Washington, DC, January 1994).

31. Energy Information Administration, *Monthly Energy Review*, DOE/EIA-0035(95/04) (Washington, DC, April 1995).

32. "Mexico to partly privatize gas sector," *Oil and Gas Journal* (May 8, 1995), p. 83.

33. "Private power key to Mexican energy strategy," *Oil and Gas Journal* (June 26, 1995), pp. 30-31.

34. Energy Information Administration, *Annual Energy Outlook 1995*, DOE/EIA-0383(95) (Washington, DC, January 1995).

3. Transportation Markets

The interstate natural gas transportation system is continuing to change nearly 2 years after the Federal Energy Regulatory Commission (FERC) issued Order 636. The order completed the transformation of the natural gas industry that began in 1985 with the issuance of FERC Order 436. Competition has increased among gas sellers, and the market power of pipeline companies has diminished. A strong resale market for transportation capacity on interstate pipelines has developed, and numerous new services have been introduced as companies position themselves to take advantage of new market opportunities.

Responding to the new market conditions, many pipeline companies have consolidated or formed strategic alliances to increase market share and gain access to new customers. For example, in recent years the gas industry has seen strong growth in the number of gas marketing affiliates and "all energy" service companies. Pipeline companies now operate more efficiently, moving more gas at a lower cost. Gas shippers have benefited from lower transmission costs, with the difference between the citygate price (average price of deliveries to local distribution companies) and the wellhead price declining by 25 percent, in real terms, since 1985.

The restructured market has created new issues and some uncertainties. During 1994, FERC took steps to clarify some aspects of the capacity release program and to ensure greater standardization of electronic information within the natural gas industry. FERC also issued a Notice of Proposed Rulemaking on alternative rate structures other than the traditional cost of service approach, and considered several pipeline company requests for market-based rates for transportation and storage services.

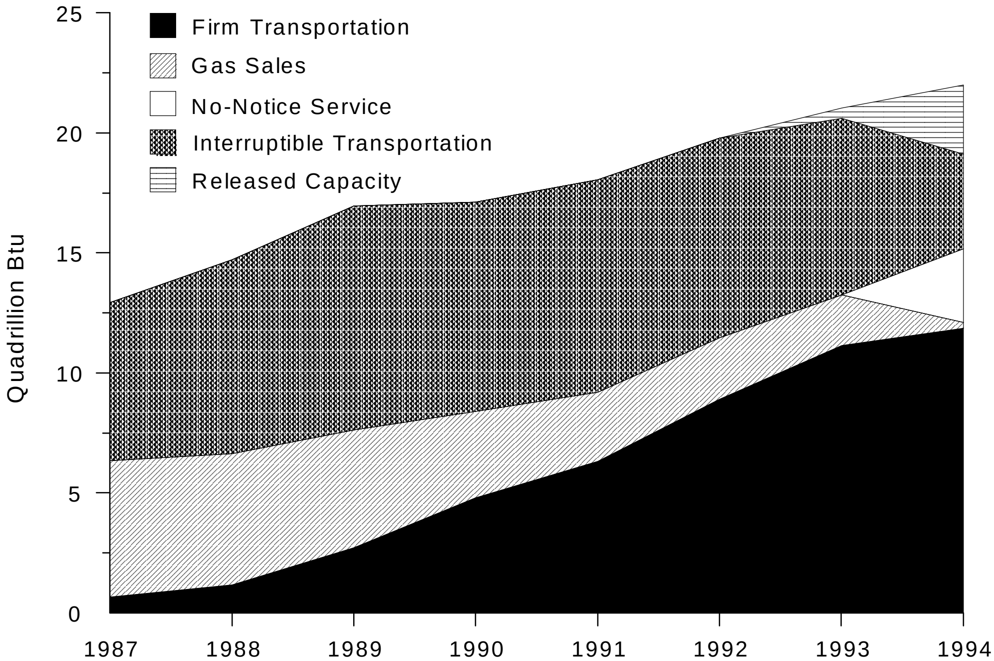
On May 31, 1995, FERC issued guidelines on how pipeline companies should recover the costs of pipeline capacity expansions. At issue was whether the cost of a pipeline expansion should be borne only by pipeline company customers who would directly benefit from the expansion (incremental rates) or whether a pipeline company could spread the cost of providing the new service over all its customers (rolled-in rates). FERC took a flexible approach that evaluates the rate structure on a case-by-case basis. FERC will permit costs of a new facility to be rolled into existing rates if the rate increase to existing customers does not exceed 5 percent and the majority of the customers receive quantifiable benefits from the new facility. When the rate increase to existing customers would exceed 5 percent, FERC may allow new facility costs to be rolled in if the pipeline company can show that the benefits of the facility are proportionate to the rate impact. Otherwise, incremental rates will be applied.

Transition costs associated with the restructuring of the interstate pipeline industry continue to be an issue for both pipeline companies and their customers. Much of the FERC-approved transition costs, which totaled $2.7 billion as of August 1995, are being recovered through charges to local distribution companies (LDC). However, it is up to the State regulatory agencies to determine how to apportion these costs among the various LDC customers. State reaction to Order 636 is a key uncertainty of today's market. Many States are reviewing and revising their regulatory policies to reflect the changes in how local distributors and electric utilities obtain their gas supplies, transportation, and other services within the unbundled market. The response from the States will determine the degree that market forces will extend beyond the citygate to the distribution sector.

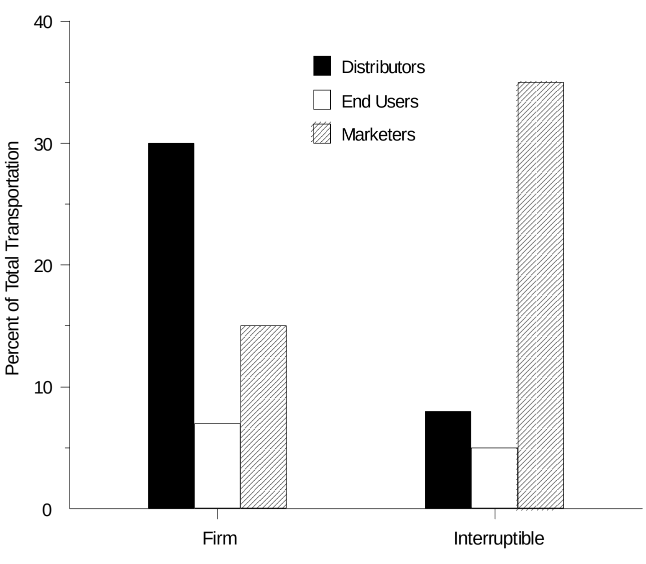
This chapter highlights some of the issues and trends related to the restructuring of the interstate pipeline industry, focusing on transportation markets during 1994, the capacity release market, electronic information transfer, State regulatory policies, and efficiency gains.

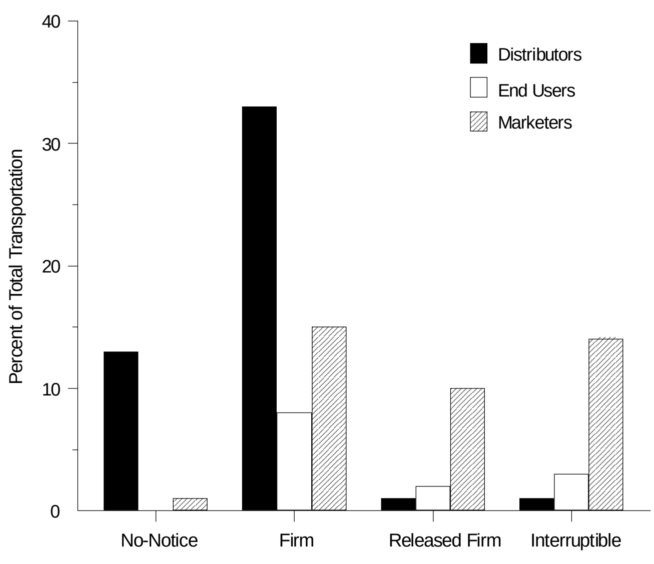
Figure 11. Firm Service Dominates the Transportation Market

Firm transportation continued to grow in 1994 while sales and interruptible transportation declined



Service options have broadened, but traditional firm services are preferred





Source: Interstate Natural Gas Association of America (INGAA), *Gas Transportation Through 1994* (August 1995).

Transformation of the Transportation Market

The interstate natural gas pipeline industry completed the shift to unbundled services in 1994. During this time, the overall size and composition of the transportation market changed substantially. Compared with 1993, total deliveries for market in 1994 increased by 5 percent and firm transportation volumes increased by 7 percent,[1] with local distribution companies (LDC's) the predominant users of transportation service. All parts of the natural gas industry continue to reorganize to take advantage of the changing market. These reorganizations are in the form of strengthening positions in core business through consolidations and expanded services, diversifications into unregulated and other energy markets, and strategic partnerships to take advantage of additional market opportunities.

- **During 1994, interruptible transportation and sales service continued to be displaced by various firm transportation services.**[2] Since the implementation of Order 636 on November 1, 1993, shippers have shown a strong preference for firm transportation services over interruptible service (Figure 11). Interruptible transportation, which represented more than 50 percent of throughput to end users in the 1987 through 1990 period, represented only about 18 percent of the market in 1994. Firm transportation services represented about 81 percent of the end-use market during 1994. This includes 13 percent for released firm transportation and 14 percent for no-notice service.[3]

- **Pipeline company customers modified their selection of services as a result of unbundling.** LDC's were the dominant segment in the transportation market in 1994, shipping approximately half of total 1994 deliveries to market, an increase of about 10 percent from the pre-Order 636 environment in 1992. LDC's used the more secure, higher quality services such as firm transportation and no-notice service (Figure 11). Marketers continued to be the primary users of interruptible transportation service, but transported a greater portion of their requirements using firm service. Marketers also emerged as the most active industry segment in the released capacity market. In 1994, end users showed a preference for firm and released firm transportation over interruptible transportation. End users also continued to increase their use of transportation services in 1994, with volumes growing 25 percent over 1993 levels and almost 50 percent over 1992 levels.

- **Interstate pipeline companies reorganized in 1993 as part of the Order 636 restructuring process, and in 1994 continued to make structural and strategic refinements**. Structural changes include consolidations and the development of mega-pipeline systems[4] and the continued transfer or sale of gathering services.[5] Pipeline companies are also offering value-added services, such as electronic information services that ease customer access to transportation.[6] In addition many pipeline companies continue to expand into unregulated business areas where growth opportunities are significant.

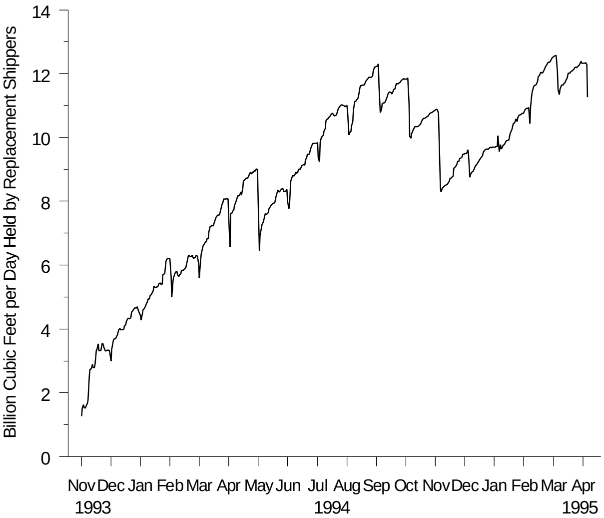
- **LDC's and intrastate pipeline companies are also reforming their business organizations in reaction to the changing transportation market**. A number of mergers have taken place on the intrastate level, and many companies have set up marketing affiliates and developed unregulated services. For example, New York State Electric and Gas purchased an energy services and fuel management company to expand services to offer software products, energy procurement services, and management products. Brooklyn Union Gas Company has an unregulated gas exploration and production subsidiary, which houses a marketing subsidiary.

- **Some pipeline companies and LDC's adopted a strategy to diversify into other energy services, rather than focusing exclusively on natural gas.** For example, Enron Gas Services renamed itself Enron Trading and Capital to emphasize the importance of financing and risk management in its menu of services and also to highlight its role as an all energy services company, as opposed to only gas services.

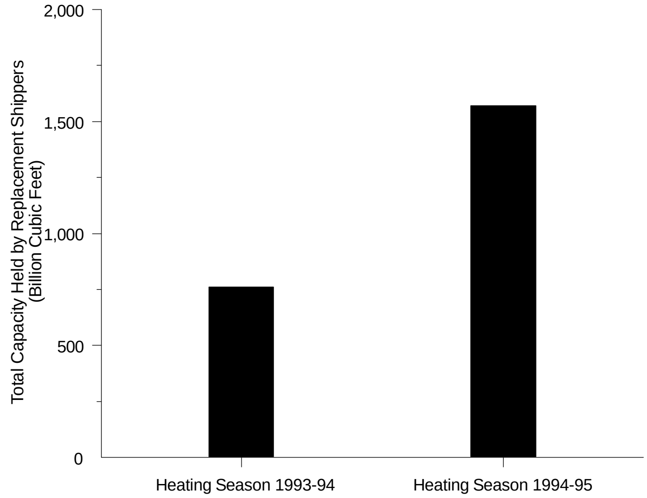
- **A number of strategic alliances developed in which separate businesses team up in gas marketing, energy, and storage ventures** to capitalize on opportunities that could not be realized by the individual entities.[7] At the same time, the additional flexibility and number of services offered enable the companies to satisfy new markets. Pipeline companies, marketers, producers, LDC's, and electric utilities have been parties to these alliances. Marketing partnerships include, for example, the teaming of Pacific Gas and Electric's Dalen Resources Oil and Gas and Consolidated Edison's ProMark Energy.[8]

Figure 12. The Capacity Release Market Continues to Develop

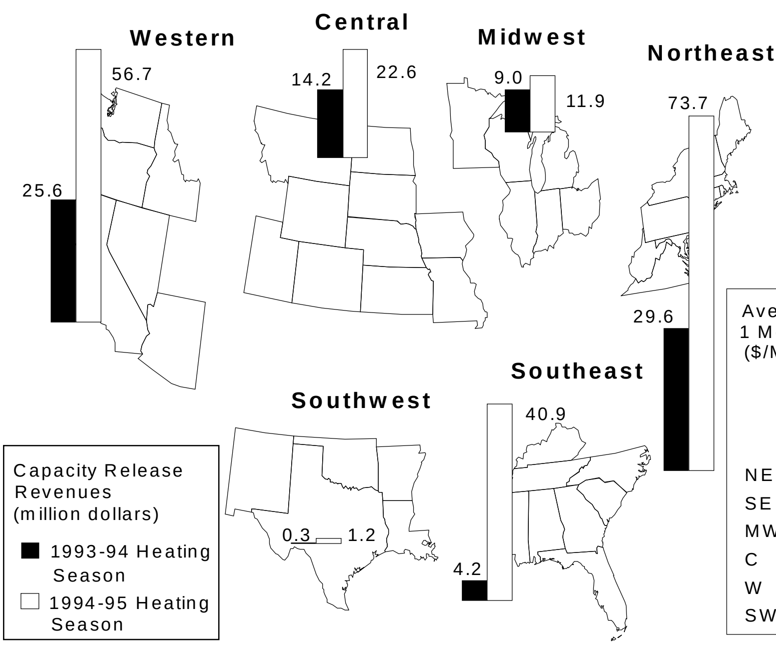
The capacity release market has experienced significant growth



Heating season pipeline capacity held by replacement shippers more than doubled



Revenues from the release of pipeline capacity have grown significantly in all regions, but average rates have been mixed



Average Cost of Acquiring 1 Mcf of Capacity for 1 Month ($/Mcf-month)

	1993-94 Heating Season	1994-95 Heating Season
NE	$4.47	$4.72
SE	$12.30	$14.13
MW	$3.81	$2.50
C	$3.89	$2.64
W	$4.69	$3.52
SW	$2.16	$6.42

$/Mcf = Dollars per thousand cubic feet.

Notes: A heating season runs from November of one year through March of the next year. Revenue calculation excludes data with capacity release rates that are stated as a percent of effective maximum rates. These data account for about 5 percent of total capacity volumes trades. Also, revenues were calculated for capacity transactions with volumetric rates assuming 100-percent load factor use of capacity.

Sources: **Volumes:** Pasha Publications, Inc. **Revenues:** Energy Information Administration, Office of Oil and Gas, derived from: Capacity release transaction data from Pasha Publications, Inc.

Evolution of the Secondary Market

A major development in the restructured interstate transportation market has been the establishment of a secondary market for retrading unneeded firm capacity. Some define the secondary market as including any capacity transaction other than long-term capacity obtained directly from a pipeline company, including: released capacity (under the Order 636 mechanism), interruptible transportation, short-term firm transportation, as well as alternative bundled services. The best known segment of the secondary market is the capacity release market initiated by Order 636 in which releasing and replacement shippers exchange capacity rights through electronic bulletin boards. While the capacity release market has grown substantially (Figure 12), some shippers are finding other ways to use their excess capacity. In fact, there appears to be a continuing market for repackaged or rebundled services offered by marketers and local distribution companies.

- **During the period from November 1993 through March 1995, capacity release grew in terms of the number of transactions and the amount of capacity held by replacement shippers.** There were more than twice as many capacity release transactions in December 1994 as in December 1993.[9] Pipeline capacity volumes held by replacement shippers during the 1994-95 heating season more than doubled to 1,570 billion cubic feet (Bcf), compared with 762 Bcf held during the 1993-94 heating season (Figure 12).[10]

- **Release transactions for pipeline capacity generated at least $528 million in revenues for releasing shippers from November 1, 1993, through March 31, 1995.**[11] Capacity release revenue for the 1994-95 heating season increased across all U.S. regions (Figure 12). The Northeast and Western regions continued to lead as the primary revenue markets, while the Southeast Region materialized as a major revenue producer in 1994.

- **Estimated average rates paid for released capacity in the 1994-95 heating season varied substantially from rates paid a year earlier (Figure 12)**.[12] The most dramatic price change occurred in the Southwest Region largely because of the expiration of a single, low-price/high-capacity transaction that was active during the 1993-94 heating season. Although the change in average rates for released capacity varied across regions, the Southeast commanded the highest average rate in both the 1993-94 and 1994-95 heating seasons. A number of factors could cause the high average rates in the Southeast Region, including pipeline capacity constraints and little available released capacity. However, sufficient data are not available to determine conclusively why the average rate in the Southeast was more than three times the U.S. average rate. Nevertheless, prices for released capacity are capped at the maximum tariff rate approved by FERC.

- **Notwithstanding the increase in use of the capacity release market, some industry participants have advocated fundamental changes in FERC's capacity release regulations that go beyond the recent adjustments that FERC made to its guidelines.**[13] Industry complaints involve the price cap on released capacity,[14] the claimed difficulties with the electronic bulletin board (EBB) systems (see next section),[15] and the competitive situation some parties have in the secondary market.[16] These problems have led some releasing shippers to explore other means to sell their excess capacity.

- **Releasing shippers may avoid some of the claimed problems and restraints of the capacity release market by operating in the "gray market."** The gray market is broadly viewed as transportation or storage capacity that is bundled with gas and sold as a deregulated service by marketers and LDC shippers. In the case of an LDC, it may involve a sale to an off-system customer.[17] A shipper with excess capacity may find it advantageous to bundle the capacity with gas supply and sell the bundled service, rather than simply releasing the capacity through the EBB's. In addition to the ease and speed of completing the transfer, releasing shippers may be able to get higher prices for their excess capacity because the capacity release price cap does not apply. It also allows shippers to keep these transactions as proprietary information because the details are not posted on the EBB's.[18] The significance of the gray market is unclear, however, because with the data currently available it is not possible to quantify its size or revenues. Currently, at least one State is investigating the gray market to determine its effect on rates for onsystem customers.[19]

- **The gray market is evidence of a continuing demand for bundled services.** Some shippers prefer to avoid the operational complexities and resources required to make arrangements for separate gas services (such as supply acquisition, storage, transportation, etc.), preferring instead to obtain a package of services. Both regulated and unregulated firms are offering these bundled services, as well as a broader range of services than previously available from pipeline companies. This gray market activity is increasing the number of gas transactions that are free of regulation.

Table 1. Key Dates in the Natural Gas Industry and the Information Highway

4/9/92	Order 636—The Federal Energy Regulatory Commission (FERC) requires pipeline companies to conduct their capacity release programs through electronic bulletin boards (EBB's).
8/3/92	Order 636A—FERC directs pipeline companies to provide for interactive EBB's in their compliance filings and encourages the industry to develop uniform standards and conventions.
11/27/92	Order 636B—FERC rejects request to delay implementation of its requirement to conduct capacity release transactions through an EBB.
12/23/93	Order 563—Includes agreement on common codes for pipelines and for locations. PI-GRID selected to be the Code Assignor, with common codes consisting of 16-digit numbers to provide unique identifiers for points.
3/10/94	Industry-wide meeting to investigate formation of a Gas Industry Standards Board (GISB)
4/2/94	Order 563A—FERC issues "Standards for Electronic Bulletin Boards Required Under Part 284 of the Commission's Regulations." Provides that Electronic Data Interchange (EDI) will be the communications standard for pipeline EBB's. Standardizes capacity release information and how shippers access it.
6/1/94	Electronic Data Interchange (EDI) promulgated by the American National Standards Institute (ANSI) becomes the approved format for capacity availability.
6/94	Williams Energy Ventures' "Streamline" system is the first electronic trading system to go on line at the Carthage hub.
7/28/94	First formal meeting of the Gas Industry Standards Board (GISB).
9/26/94	Incorporation of GISB, whose mission is to facilitate transactions through the development of standards applying to electronic information exchange and electronic communitcation.
11/1/94	Computerized cross-reference database with common codes to be available without charge from pipeline companies, except for distribution and handling fees.
12/14/94	First trading on Williams Energy Brokering Co.'s "Capacity Central" electronic capacity trading system. (Provides access to six major gas pipeline and transmission companies.)
3/95	NrG Highway is in production. Secured services include administrative functions, nominations, and customer operational data. On-line contracting will be available in the future.
3/1/95	Electronic gas trading is now in place, or expected to be in place soon, at 18 market centers.
3/15/95	Tejas Power affiliate Prism Information's trading system, "Rapid Exchange," comes on line at the Moss Bluff market center in East Texas.
4/5/95	Twenty companies testing EnerSoft Corp and New York Mercantile Exchange's (NYMEX) "Channel 4" electronic gas and pipeline capacity trading and information system. System will offer three kinds of gas trading and one capacity trading module and will allow access to all U.S. pipeline points and market hubs.
4/10/95	Announcement that GISB is teaming with GasEDI, its counterpart in Canada, to develop common North American Standards governing electronic trading in the natural gas industry.
5/10/95	Columbia Energy Market Center's "The Fast Lane" offers real-time electronic trading of gas supplies and capacity.
8/10/95	Canadian-based Energy Exchange and Natural Gas Clearinghouse agree to operate electronic gas trading systems to be used in Canada and the United States. The new system, Quick Trade, will be operational in the Chicago hub in the fourth quarter of 1995.
8/11/95	Channel 4 system goes on line.
8/17/95	NrG Corporation and Natural Gas Exchange (NGX) link up and plan to have an electronic gas trading system ready in September. Customers of the NrG Highway will be able to buy and sell gas and get real-time pricing using this link to NGX. These services are temporarily limited to Canadian users with the probability of connecting to William's Streamline System for U.S. use in the future.

Sources: Federal Energy Regulatory Commission (FERC), FERC memorandum and attachments regarding Gas Industry Standards Board (Feb. 24, 1994). Pasha Publications, Inc., *Gas Daily*, various issues.

The Information Highway and the Natural Gas Industry

FERC Order 636 ushered the natural gas industry into the electronic information age by requiring interstate pipeline companies to use electronic bulletin boards (EBB's) for capacity release information and transactions. When the first EBB's became operational in 1993, it quickly became apparent that some system standardization was needed. This led to the creation of working groups, consisting of members from FERC and from the industry, to develop standards for information exchange. In 1994, these initiatives gained momentum and FERC provided further guidelines.

- **At present, all large interstate pipeline companies and storage facilities have operating bulletin boards**. But the number of capacity release transactions carried out on EBB's varies greatly from one pipeline to another. Accessing the EBB's is often complicated, which can restrict EBB activity. The most difficult aspect of working with EBB's is their great variety. The most rudimentary EBB's merely display information, and in some cases permit users to post information. More sophisticated EBB's have standardized file transfer capability. Users can download the information from the board to their own computers, work with the information, and then upload it back to the EBB. The EBB's of the future will go one step further and provide real-time information network connections. These systems will permit continuous information exchange between the pipeline companies and shippers.

- **FERC took several steps in 1994 to improve the efficiency of capacity release through EBB's** (Table 1). FERC Order 563A standardized the content and procedures for accessing information of EBB's through Electronic Data Interchange (EDI). This standardization will benefit the capacity release participants by making it easier for potential shippers to locate and contract for capacity from any pipeline system. In November 1994, FERC ordered shippers to report EDI information on the maximum tariff rate for transportation service, as well as the actual price paid for that service. These steps moved the industry toward the January 1, 1997, target date for full electronic data interchange for Federal agencies.

- **In the future there will likely be information systems giving real-time access to virtually all the major pipelines**. By the end of 1994, the industry recognized that more centralized systems would be valuable. The following systems are now being developed or expanded:

  —Capacity Central - A real-time electronic brokering system matching spot buyers and sellers of excess firm capacity in the less-than-30-day capacity market. The Windows-based system began trading December 14, 1994, with six pipelines available. Additional pipelines are scheduled to be included by the end of 1995.

  —NrG Highway - A Windows-based system covering Canadian pipelines, which will be upgraded to allow on-line contracting and provide a link to U.S. pipelines.

  —Rapid Exchange - Tejas Power affiliate Prism Information's electronic trading system, which went on line on March 15, 1995.

  —Channel 4 Enersoft and NYMEX's gas trading system, which provides access to multiple pipelines, came on line in August 1995.

- **The Gas Industry Standards Board (GISB) was formed in 1994, with representatives from both industry and Government, to promote a more consistent system for data exchange**. Its procedures for electronic data exchange were approved in May 1995 and became available for use by any of its 183 members. Its proposed standards for capacity release were approved by the Board in July, and its proposals for gas transportation information were released for preliminary inspection in July. These latter proposals await final approval by two-thirds of the membership.

- **Electronic trading is also making its appearance at market hubs.** Electronic trading systems allow users to buy and sell gas and capacity rights. Buyers and sellers can (1) check price and availability of gas at market hubs and other transaction points, (2) submit bids and offers, (3) complete legally binding transactions, and (4) prearrange capacity releases.

- **The key to the success of electronic trading is the development of "standard instruments."** These vary by trading system. In mid-1995, electronic gas trading is available at 18 market centers and 2 other transaction points. With electronic trading, or automatching, the system anonymously fills gas orders with offers by a simple algorithm. The highest bid for gas is matched with the lowest offer of gas at the price of the offer. Timestamping and queues are used to break ties. In addition to electronic trading, there are electronic information systems at market centers. One type of system supports actual trading of gas and firm capacity rights. Another type of system supports gas management control activities.

Table 2. Recent Regulation Implemented by States as of May 1995

State	Regulation Implemented or Guidelines Issued			State Policy
	PBR	CRR	U	
California	X		X	Implemented performance-based regulation on the purchase of natural gas for San Diego Gas & Electric in 1993 and adopted a gas cost incentive mechanism for SoCal Gas in 1984. Reselling capacity and sharing the resultant revenues is not an issue in California because there is an abundance of capacity. Comprehensive unbundling of gas utility services has been underway since 1984.
Colorado			X	PBR is under consideration. Capacity release revenue sharing is not currently being considered. On May 30, 1991, issued Gas Transportation Rulemaking adopting open access for all gas utilities in the State.
Connecticut			X	PBR is not under consideration. In July 1994, issued a decision that capacity release credits flow through Purchased Gas Adjustment (PGA) to firm rate payers. In the same decision, Commission required service unbundling to begin no later than November 1, 1995.
Illinois	X		X	Legislation passed in May 1995 allowing companies to present PBR proposals to the State Commerce Commission for review and possible implementation. Capacity release crediting is under consideration, however, a sharing breakdown has not been submitted. Unbundled services have been available for several years.
Iowa		X	X	Offers flexible rates and anti-bypass rate provisions, but does not have any specific order detailing PBR's. In October 1994, issued an order crediting 70 percent of revenues from capacity release to customers with the remaining 30 percent for the company. In 1984 passed the Mandatory Transportation Access regulation, which required LDC's to open distribution system for transportation to end users.
Missouri				PBR is currently under consideration in a special case submitted by a utility. Capacity release revenue crediting has not been implemented. Unbundling has not been implemented extensively for LDC's.
Maryland			X	PBR is currently under consideration in a company rate case. Capacity release revenue is credited 80 percent to customers through the PGA. Issued four major recommendations regarding unbundling. LDC's should offer a range of unbundled services and ultimately replace retail sales service with unbundled city-gate supply service and unbundled delivery service. The three largest LDC's are required to implement unbundled services for all larger volume customers effective November 1, 1995, and on a pilot basis for small volume customers effective November 1, 1996.
Massachusetts	X		X	Issued an order in February 1995, detailing the filing procedures for companies wishing to file for PBR's. Capacity release revenue crediting is under consideration, with an order scheduled for release in September 1995. Unbundling for some transportation services and interruptible transportation is allowed.
New Jersey		X	X	Reviewed PBR's and decided not to pursue implementation at this time. LDC's must pass back 80 percent of the compensation they receive on pipeline capacity-release transactions to firm customers with the remaining 20 percent retained by the company. Approved several unbundling plans for classes other than residential that comply with its December 1993 Guidelines for Further Unbundling of New Jersey's Natural Gas Services.
New York	X	X	X	Implemented PBR's. LDC's can retain 15 percent of the revenues received from capacity release with 85 percent going to core customers. LDC's must unbundle services to firm customers, including access to upstream facilities such as pipeline capacity, storage, and receipt points.
North Carolina		X	X	Provisions for PBR legislation are not under consideration. The State utility commission ruled that LDC's in the State must pass back to ratepayers 90 percent of the compensation they receive on pipeline capacity-release transactions, with the remaining 10 percent for the company. The State utility commission has filed a petition to investigate gray market or buy/sell transactions. Unbundling is considered on an individual LDC basis—as each utility files a rate case, certain service unbundling features have been proposed. Comprehensive regulation has not been passed regarding unbundling.
Pennsylvania	X			PBR's have been approved on a company-specific basis; legislation has not, however, been passed statewide. There have not been any specific orders addressing capacity release revenue sharing or unbundling.
Wisconsin	X	X		Approved a natural gas procurement incentive program, Productivity-based Alternative Ratemaking Mechanism (PARM), as well as capacity release crediting on a utility specific basis. Hearings are currently being held regarding unbundling; a decision is anticipated in the spring of 1996.

PBR = Performance-based ratemaking; CRR = Capacity release revenue crediting; U = Unbundling; LDC = Local distribution company.

Source: The National Regulatory Research Institute, *A Survey of Recent State Initiatives on EPACT and FERC Order 636* (October 1994) and State regulatory commissions.

State Regulatory Issues

The intrastate natural gas market is in a state of flux as regulators, local distribution companies,[20] and end users adjust to the effects of FERC Order 636. While significant changes have been made in a number of areas, the transition is far from complete. In addition to traditional regulatory solutions, in some cases State regulatory commissions and industry participants are employing innovative methods, such as performance-based ratemaking and flexible rates, to respond to competitive and operational changes in the intrastate market.

- **Of the 13 States reviewed, 10 have issued guidelines for unbundling the distribution sector (Table 2).**[21] The unbundling focus thus far has been on the industrial and large commercial customer classes.[22] However, some plans will include residential and small commercial customers in the future.[23] In an unbundled retail environment, customers may be able to save money by purchasing the gas themselves and arranging separately for transportation and storage services. A drawback of unbundling is that end users who wish to replace sales service with transportation service must develop the knowledge needed to arrange reliable and adequate service. Also, as more customer classes take over the responsibility of acquiring/arranging for natural gas service, the local distributors' obligation to serve may need to be reviewed by State regulatory commissions.

- **Bypass is a difficult issue for State and Federal[24] regulators.** Bypass results when a customer connects directly to a transporter rather than receiving service from the local distributor. Usually bypass occurs because there is some cost incentive for the customer. However, cancellation of a service contract with the local distribution company (LDC) causes the remaining customers to bear a larger share of the LDC's capital costs. State regulators balance the merits of competition with the disadvantages faced by the remaining customers of the bypassed LDC. As a result, regulatory agencies typically review proposed bypass on a case-by-case basis. In situations where bypass has been determined to be undesirable, many States have undertaken efforts to grant the LDC rate flexibility where necessary to retain a customer threatening bypass. In some cases, States have considered eliminating some advantages that direct interstate pipeline connections have offered instead of broadly ruling against bypass.[25]

- **State regulatory bodies generally require LDC's to credit capacity release revenue to firm sales customers through the Purchased Gas Adjustment charge (PGA).** For example, North Carolina requires LDC's to pass back to ratepayers 90 percent of the compensation it receives from pipeline capacity-release transactions (Table 2).[26] Some States have also approved sharing procedures for revenue from onsystem and off-system sales of the LDC's marketing affiliate.[27] These issues will become more important as LDC's gain more experience in directly contracting for their own transportation and storage requirements.

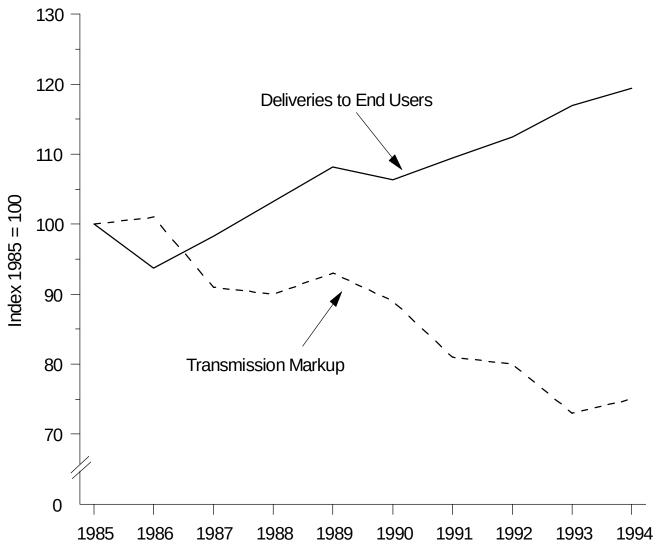
- **According to a 1994 survey of 78 LDC's, transition costs equal about 5 percent of total gas supply costs**. In general, LDC's recover transition costs through their PGA charge. Although PGA costs are normally collected from firm service customers, in some cases State regulatory bodies have directed LDC's to allocate transition costs on a volumetric basis and collect them from all customer classes.[28] Transition cost recovery may continue to be an area of discussion as competition in the intrastate market spurs bypass.

- **Performance-based rates[29] appear to be an unfolding topic at the State level.** In most cases, performance-based rates have been proposed by the LDC's, although some State regulatory agencies have actively promoted their use (Table 2). Such rates could benefit LDC customers because of their focus on service quality improvement, cost savings, and revenue sharing principles.[30]

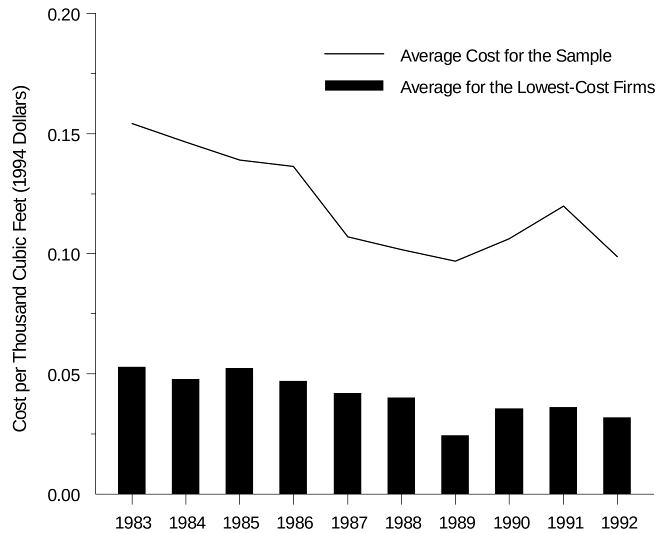
- **Integrated resource planning (IRP) and demand- side management (DSM) may help LDC's operate competitively in the new environment.[31]** Several companies set up IRP and DSM plans as required by the Energy Policy Act of 1992, which emphasized conservation and efficiency improvements. Although interest in these programs has declined,[32] they can help companies select the most economical and efficient course of action. IRP may help LDC's assess issues that were not traditionally part of their planning processes, such as the influence of competition and the need to consider the early retirement of existing capital equipment. DSM techniques, such as increasing off-peak use of the system ("valley filling"), should help an LDC to operate more efficiently.[33]

Figure 13. Efficiency Improvements Result in Lower Transportation Costs

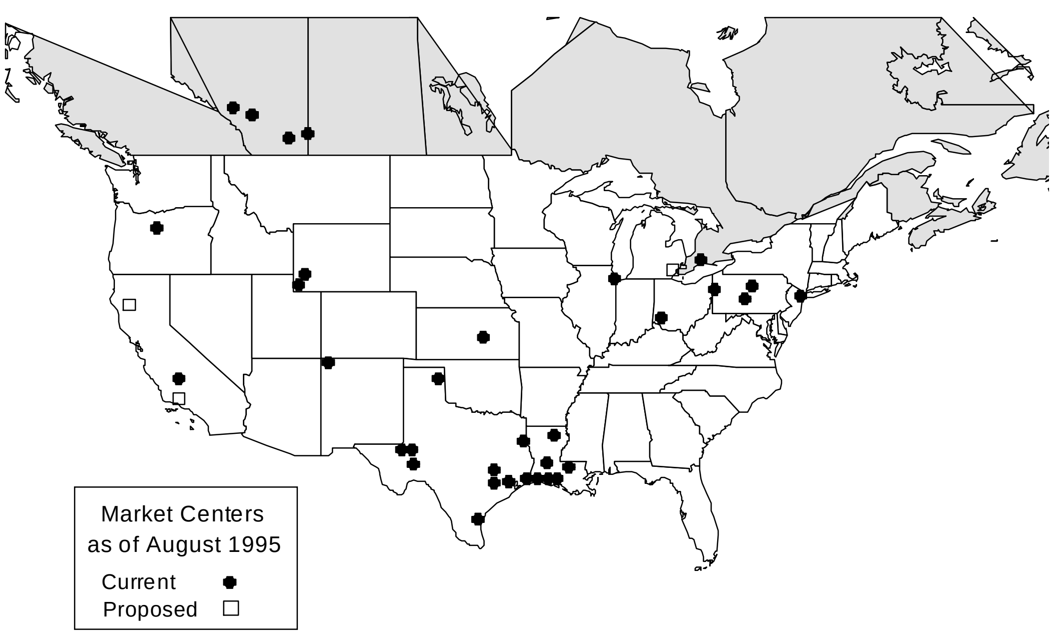
Natural gas transmission markup declined as deliveries increased



Average operating cost of the typical firm is approaching that of the low-cost firm



Market centers are no longer confined to production areas



Note: Operating costs are based on a sample of 25 major pipeline companies. Fuel costs and transmission and compression of gas by others are excluded. The transmission markup is calculated as the difference between the average citygate price and the average wellhead price.

Sources: Energy Information Administration. **Transmission Markups and Deliveries to End Users:** Office of Oil and Gas, derived from: 1985-1988—*Historical Monthly Energy Review* (August 1994); 1989-1994—*Natural Gas Monthly* (August 1995). **Operating Costs:** Office of Oil and Gas, derived from: Federal Energy Regulatory Commission, FERC Form 2, "Annual Report of Major Natural Gas Companies." **Market Centers:** Office of Oil and Gas, based on information from various news sources.

Efficiency in the Gas Transmission Industry

In 1985, the Federal Energy Regulatory Commission (FERC) issued Order 436, which provided for third-party open access to the pipeline system. While some analysts had predicted that open access would reduce the efficiency of the system, there appears to be a growing recognition that the system is actually more efficient today than in 1985.[34] Shippers can now take advantage of lower cost supply and transportation options that were unavailable when transportation was bundled with sales. More recently, the unbundling of pipeline services under FERC Order 636 and the development of market centers are also believed to have increased efficiency. Although the industry remains highly concentrated in terms of the share of interstate deliveries accounted for by the largest pipeline companies, effective competition has increased as a result of the restructuring.[35] Specifically, the unbundling of transportation services, the increase in the number of potential suppliers of pipeline capacity as a result of the secondary market, and the increased pipeline interconnections have provided shippers with competitive alternatives to traditional pipeline transportation services. In response to this increased competition, the pipeline companies have undertaken efforts to improve the efficiency of their operations.

- **Increased competition has contributed to higher throughput and a lower transmission markup.** Total deliveries to end users increased by more than 19 percent from 1985 through 1994.[36] During the same period, the transmission markup, as measured by the difference between the average citygate price[37] and the average wellhead price, declined by 25 percent in real terms (1994 dollars) from $1.66 per thousand cubic feet in 1985 to $1.25 in 1994 (Figure 13). In 1994, transmission markups increased on average by 3 percent in real terms relative to 1993. This increase may be due, in part, to the effects of the new straight fixed-variable rate design and the transition costs of the interstate pipeline companies.

- **Natural gas deliveries per employee have dramatically increased.** Employment in the transmission segment in 1993 was 13 percent below the level in 1985.[38] This decline, in conjunction with the increase in systemwide deliveries, has resulted in a 35-percent increase in natural gas deliveries per employee.

- **Operational efficiency has improved as the increase in competition has motivated the pipeline companies to be more cost efficient.** Indicative of this trend is the decline in the differential between the costs of the "typical" firm as compared with the firm with the lowest costs. Specifically, average transmission operation and maintenance expenses for a sample of 25 major pipeline companies in 1985 equaled $0.14 (1994 dollars) per thousand cubic feet (Mcf) of gas delivered, while the firm with the lowest costs was able to move gas at a cost of $0.05 per Mcf.[39] Between 1985 and 1992, operation and maintenance expenses declined by 29 percent to $0.10 per Mcf of gas delivered (Figure 13). The difference in operating costs between the typical and the lowest cost firm(s) decreased by 22 percent, from $0.09 per Mcf in 1985 to $0.07 in 1992.

- **Administrative efficiency has improved.** In 1985, total administrative and general expenses for a sample of 25 major pipeline companies averaged $0.14 per Mcf of gas delivered—$0.11 more than the $0.03 (1994 dollars) per Mcf reported by the pipeline company with the lowest costs. With costs averaging $0.09 per Mcf in 1992, the differential was a more modest $0.06 per Mcf. Much of this improvement can be attributed to cost reduction undertaken by the companies with the highest costs. For example, in 1985, administrative costs for the pipeline company with the highest costs were $0.50 per Mcf; in 1992, costs for the same pipeline were $0.16 per Mcf.

- **The emergence of the secondary market has increased efficiency by allowing shippers to transfer their firm capacity rights to those who value it most.** It also improves efficiency by making the market for pipeline capacity more competitive. Before existence of a secondary market, transportation rights on a given pipeline could be obtained only from the pipeline company itself. Now, a shipper could potentially obtain capacity from an average of almost 70 holders of capacity rights on a given pipeline.[40] This increase in the number of potential suppliers of capacity on a given pipeline preserves the economies of scale inherent in transmission, while effectively providing for a competitive, i.e., efficient, market in pipeline capacity.

- **Market centers have increased system efficiency and competition by providing shippers access to more supply and transportation options (Figure 13).** Market centers promote efficiency by making price information easily accessible. This enables buyers to select the supply they want at market cost and enables sellers to target the market with the best price. New developments in hub services include hub-to-hub swapping, which enables customers to deliver gas to one hub and simultaneously receive gas from another hub. While hub-to-hub swapping is currently only available in Canada, its introduction into the United States is likely given the potential savings in transmission expenses.

Chapter 3 Endnotes

1. Based on data from the Interstate Natural Gas Association of America on total natural gas delivered to markets, including all transportation for distributors, end users, and marketers, plus pipeline sales. It excludes gas transported for other pipeline companies.
2. Besides traditional firm service, firm transportation services include released firm transportation, no-notice transportation, and short-term firm transportation. A pipeline company may sell the unused portion of any firm transportation capacity on its system on a short-term basis.
3. While specific tariff provisions vary from pipeline to pipeline, no-notice service is generally a combination of storage and firm transportation services that is 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 sales service. It allows the shipper to use their full capacity commitment without advanced scheduling through the use of storage services. LDC's frequently supplement their firm transportation needs with no-notice service in order to provide the most reliable service to their high priority customers.
4. To augment the existing pipeline network, a number of pipeline companies have purchased additional miles of pipe or acquired transmission companies with substantial in-place systems. The transmission companies have remained separate entities, however. For example, the Williams Company added more than 17,000 miles of pipeline to its system when it merged with Transco Energy Company in December 1994. This purchase results in the first coast-to-coast pipeline network owned by one parent with the greatest throughput of any pipeline company in the industry.
5. Many pipeline companies decided to sell or separate their gathering services from jurisdictional services in 1994, after FERC ruled on the scope of regulation applicable to separate gathering services. FERC ruled that if a pipeline company abandoned and transferred or sold its gathering, the facilities would not be subject to FERC jurisdiction.
6. "Tenneco paves the way for integrated EBB in U.S."*Gas Daily* (October 21, 1994), p. 1.
7. "How Sweet Are Merger Deals?" *Gas Daily's NG* (April/May 1995), p. 35.
8. Additional marketing partnerships include: Mobil Natural Gas and Reliance Energy Services, Brooklyn Union Gas' Brooklyn Interstate Natural Gas and Pennzoil; Norstar Energy and Shell Gas Trading. HNG Storage of Houston and Houston Lighting & Power are working jointly. Four local distribution companies (in the Midwest and Eastern regions) formed a partnership with Tejas-Power to develop, own, and operate five natural gas market centers and provide storage, cash-market trading, real-time title tracking, and other hub services.
9. A capacity release transaction includes the offer of capacity by a releasing shipper and the purchase of all or some portion of that capacity by a replacement shipper. There were 1,108 and 457 active pipeline capacity release transactions in December of 1994 and 1993, respectively. Data provided by Pasha Publications, Inc.
10. A heating season is the 5-month period beginning November 1 of one year and continuing through March 31 of the following year. The heating season is normally characterized by maximum utilization of the pipeline capacity.
11. Electronic bulletin board data were supplied by Pasha Publications, Inc. Revenues were calculated using transactions with complete information concerning the rate charged, charge type, capacity amount, and release duration. They exclude data with capacity release rates that are stated as a percent of effective maximum rates, capacity transactions with incomplete data, and one transaction with an inconsistent release rate. The excluded data account for 10 percent of the pipeline capacity traded from November 1, 1993, through March 31, 1995. Revenues for transactions with volumetric rates were calculated assuming 100-percent load factor use of the acquired capacity. Release transactions for storage capacity generated an additional $40 million in revenue credits.
12. The average rate per region was calculated by dividing the total revenue from the capacity released on the electronic bulletin boards by the sum of the capacity held by replacement shippers for 1993 and 1994. The rates indicate the average cost of holding an Mcf of capacity per day for an entire month in the respective region.
13. FERC Order No. 577, issued March 29, 1995, exempted all prearranged releases with a term of up to one calendar month from the advance posting and bidding process, thus ending the need for paired 29/1 transactions. Paired 29/1 transactions were developed by the capacity release participants to avoid the open bidding requirement for release contracts at less than the maximum rate with terms lasting 30 days or more. Releasing shippers would enter into a prearranged 29-day contract and hold an open bid for 1- or 2-day contracts to complete a calendar-month transaction. On April 26, 1994, FERC approved Order 536-

A, which, in addition to clarifying certain requirements and protocols, established Electronic Data Interchange (EDI) as the communications standard for pipeline electronic bulletin boards.

14. Some releasing shippers would like to remove the cap on the maximum rate for released capacity to promote FERC's policy that market forces, where possible, should dictate the price of gas, or to offset the effect of straight fixed-variable rate design. Marketers generally oppose removing the price cap for fear that LDC's could out-bid them for the capacity and pass the costs through to their captive customers. End users have expressed concern that lifting the price cap may increase the overall cost of transmission.

15. Order 636 requires all pipeline companies to use electronic bulletin boards (EBB's) to satisfy the requirement "that pipelines must provide timely and equal access to any and all information necessary for buyers and sellers to arrange gas sales and capacity reallocations." FERC Docket No. RM91-11-000, April 8, 1992, p.70. Some shippers (and even some FERC Commissioners) have stated that the plethora of different electronic bulletin board systems are "awkward, inefficient and over-regulated." *Natural Gas Intelligence* (April 10, 1995), p. 11.

16. Releasing shippers have asserted that interruptible transportation (IT) has an unfair advantage over released capacity because IT transactions are not required to be posted on the pipeline companies' electronic bulletin boards. Interstate pipeline companies and marketers argue that the LDC's could exercise considerable market power with their capacity rights and force customers to purchase bundled services. According to some releasing shippers, short-term firm capacity also has an unfair advantage over released capacity, because the pipeline company can identify unused capacity based on the operational status of its system and through the electronic bulletin board postings. Pasha Publications, Inc., "Short-term FT may threaten capacity-release," *Gas Transportation Report* (December 7, 1994), p. 1.

17. An off-system sale is a sale to a customer other than one of the company's firm sales customer (e.g., outside the company's traditional service area).

18. The gray market may enhance a shippers competitive position with respect to other secondary market transactions because capacity sellers (pipelines as well as other firm shippers) would not be able to view transaction details through the electronic bulletin boards.

19. The North Carolina Utilities Commission is concerned that onsystem customers are not receiving the revenue benefit that would otherwise be generated by released capacity.

20. While this discussion emphasizes the local distribution company (LDC), many of the issues are equally important to intrastate pipeline companies. The difference between an intrastate pipeline and an LDC is that intrastate pipelines do not have distribution systems. This distinction is becoming blurred, however, as mergers and acquisitions change the profile of the intrastate industry.

21. Local distribution companies generally provide a bundled gas service to their customers. That is, the LDC purchases gas from a producer and charges its customers a gas sales rate that includes all the costs of delivering the gas from the wellhead to the end user. Hence, this rate would include the cost of the gas commodity, the transportation on the interstate and intrastate pipelines, costs associated with storage facilities and distribution costs, and the markup on the gas services. In an unbundled environment, the end user purchases the gas at the wellhead and separately contracts for the interstate/intrastate transportation and storage services and pays only for its transportation and distribution service. As early as 1986, Canada began implementing the unbundling of gas distribution service from gas commodity service by allowing and encouraging end users to arrange the purchase of gas. More recently in the United States, some State commissions have established capacity brokering for noncore customers (generally customers with other service options, such as industrial firms and electric utilities).

22. In some States, LDC's have been encouraged to rent out their distribution lines to customers who wish to purchase their own gas or to marketers wishing to sell supplies combined with transportation and distribution services to end users. The LDC must first have separately priced or "unbundled" distribution service for a marketer or end user to utilize it. For example, in April 1995, Tenneco Gas Marketing Company launched the first program to sell gas directly to end users through a nationwide network of independent marketers. Tenneco foresees the utility market unbundling as an opportunity to sell eventually to residential units.

23. For example, in the recommendations issued by the Maryland Public Service Commission in December 1994, LDC's should offer a range of unbundled citygate services and ultimately replace retail sales service with unbundled citygate supply service and unbundled delivery service. The three largest LDC's are required to implement unbundled services for all small volume customers effective November 1, 1996, on a pilot basis.

24. The bypass policy issued by FERC requires that the bypassed-LDC prove relief is needed because of revenues lost because of bypass. When a need has not been shown, FERC has not granted any relief to the bypassed LDC. In other cases, FERC has ruled that the pipeline company (effecting the bypass) must provide the bypassed LDC with a contract demand (CD) reduction to the extent the end user does not renew its contract for firm service with the LDC. For example, "FERC, Applying Its LDC Bypass Policy, Concludes that Paiute Need Not Grant Sierra Pacific a Contract Demand Reduction But Texas Gas Transmission Must Provide Western Kentucky the Lower CD Option," *Foster Report*, No. 2019 (March 2, 1995), p. 24.

25. For example, Illinois has considered taxing interstate pipeline gas delivered to an industrial end user similar to the way distributors' gas has been taxed. Daniel Macey, "Bye Bye Bypass," *Gas Daily's NG* (February/March 1995), p. 14.

26. For unregulated shippers, such as marketers, the revenue credits are not passed along to their customers.

27. The Maryland and New York public utility commissions have approved a sharing mechanism for off-system sales. Ms. Susan Parker, "Off-System Sales Work Better Than Capacity Release for LDCs," *Natural Gas Intelligence* (March 6, 1995), p.5.

28. Fifty percent of those respondents recovering costs collect a portion of the costs from interruptible customers. See also, Illinois Commerce Commission, Re FERC Order 636 Transition Costs, 155 PUR4th 331, September 21, 1994; as amended September 30, 1994.

29. Performance-based ratemaking (PBR) is a method by which a utility's future earnings are dependent on its past performance. Under this method, rate increases are justified if the utility achieves various goals. There are two basic types of incentive targets used for PBR's. In one, the utility's performance in one or more targeted areas is compared with an external benchmark. The other measures the utility's overall financial health. PBR's are commonly designed to ensure that the customers receive a share of the cost efficiency savings. This ratemaking method is different from traditional cost-based ratemaking in which the utility must prove that a rate increase is deserved because operating costs have increased, the utility made prudent capital investments, or throughput has dropped.

30. For example, the California Public Utility Commission allowed San Diego Gas & Electric (SDG&E) to implement PBR's on August 3, 1994. The mechanism approved provides for revenue sharing with customers should SDG&E earn 1 percent or more above its authorized rate of return. SDG&E, *1994 Annual Report*, p.19.

31. Integrated Resource Planning is an energy evaluation process, which assesses a comprehensive set of supply- and demand-side possibilities to satisfy short-term and long-term energy service needs of customers at the lowest total cost. Demand-Side Management is a technique whereby the utility attempts to exercise some control over its energy requirements by increasing the efficiency of the system or by influencing its customers' usage patterns. DSM includes energy conservation, energy efficiency, and load management techniques such as peak shaving and valley filling.

32. The Illinois Commission used a formal case-tracking system to study the costs associated with implementation of gas IRP. On the supply side, it determined that implementation would result in additional direct and indirect costs to ratepayers of $40 million. The demand-side management programs were shown to be cost-effective only if the cost of gas supply increased by 300 percent. The Illinois Commission demonstrated these findings to the State legislators, and gas IRP legislation was repealed on August 12, 1993. Ruth K. Kretschmer and Larry J. Mraz, "A Real Loser," *Public Utilities Fortnightly* (March 1, 1994), pp. 17-20.

33. Increased use of the system during off-peak periods improves the system's load factor, thus improving efficiency. The load factor is calculated by dividing the average daily volume by the peak-day volume. For example, if a customer has an annual throughput of 730 thousand cubic feet (Mcf) and a peak-day demand of 4 Mcf, that customer has a 50-percent load factor ((730 Mcf/365 days)/4 Mcf peak day = 0.5 = 50 percent).

34. For a discussion of potential problems or inefficiencies under open access, see David J. Teece, "Structure and Organization of the Natural Gas Industry: Differences between the United States and the Federal Republic of Germany and Implications for the Carrier Status of Pipelines," *The Energy Journal*, Vol. 11 (July 1990), pp. 1-35.

35. For instance, Florida Gas Transmission is the only pipeline company serving large portions of Florida. As a result, its weighted average share of total interstate deliveries in 1992 to LDC's and end users in Florida and the other States it serves was 85 percent based on data from Energy Information Administration, Form EIA-176. Similarly, in 1992, Northwest Pipeline accounted for almost 90 percent of interstate deliveries in Washington and the other States that it serves. Other pipeline companies with high market shares include Algonquin (75 percent), Natural Gas Pipeline (71 percent), El Paso (55 percent), East Tennessee (54 percent), Colorado (53 percent), Columbia (45 percent), and Transcontinental (42 percent).

36. Energy Information Administration, *Monthly Energy Review*, DOE/EIA-0035(95/05) (Washington, DC, May 1995), Table 4.4, p. 76.

37. The citygate price is the average price of the gas delivered to the local distribution company.

38. Based on the employment levels reported by the Bureau of Labor Statistics for the Standard Industrial Classification code number 4922.

39. Excludes fuel expenditures and transmission and compression expenses by others. Data are from Federal Energy Regulatory Commission, FERC Form 2, "Annual Report for Major Natural Gas Companies." As of the date of this publication, 1992 was the most recent year for which the data were available.

40. See Arthur De Vany and W. David Walls, "Natural Gas Industry Transformation, Competitive Institutions and the Role of Regulation," *Energy Policy*, 22 (9) (1994), pp. 755-763.

4. Deliverability on the Transmission Network

The natural gas pipeline network in the United States has evolved during the past 50 years into an efficient and highly integrated transmission and distribution operation. An indication of the importance of this network is that 27 of the lower 48 States are totally dependent upon the interstate system for their natural gas supplies, which must be transported from 11 producing States, located primarily in the Southwest and Central regions of the country. More than 1,200 local distribution companies nationwide distribute these supplies to the ultimate consumer.

The previous chapter discussed the changing contractual and business relationships affecting the interstate transportation of gas. These changes have affected the operation of the pipeline system as well, providing the impetus for significant expansion of the pipeline system during the past 4 years, for the development of market hubs, and for changes in the way storage is used throughout the year. New pipelines were built and existing facilities enhanced or replaced in order to increase the volume of gas that can be transported to meet expected growth in customer peak demands. Pipeline companies now offer a variety of services, such as short-term volume loans, temporary parking (of gas that cannot be immediately delivered), and equity transfers as a means of facilitating flows and attracting and keeping customers.

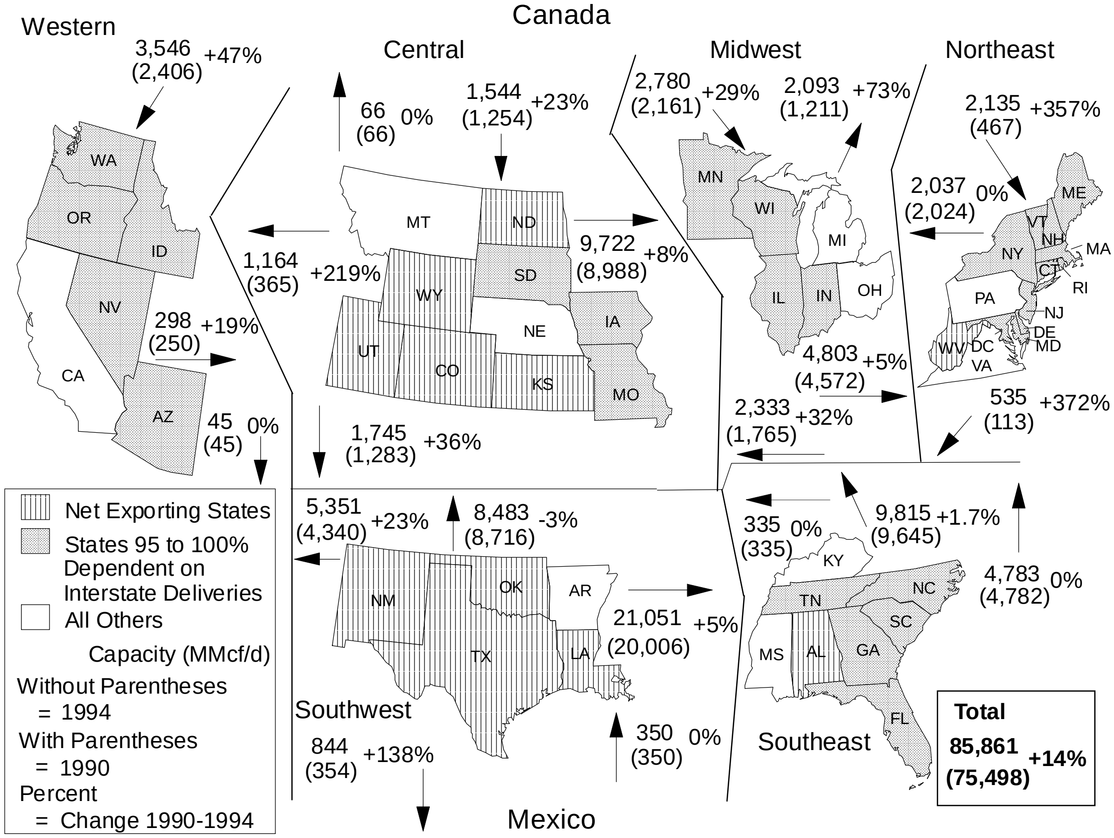
The market/supply hub concept has emerged to accommodate and facilitate transactions between buyers and sellers in a more flexible marketplace where the delivery volumes often must be transported along several pipelines to reach the ultimate destination. Today at least 24 hubs are operating in the United States and 5 in Canada, and at least 6 more have been proposed. Not surprisingly, 10 are located in Texas and 5 in Louisiana—States where a number of hub points naturally exist because of their predominance of production, pipeline interconnections, and storage facilities.

Underground storage has become more highly integrated into the daily operations of the national pipeline grid. The ability to deliver gas to meet peak customer requirements is typically predicated on the availability of storage inventories. Pipeline deliverability is being improved with the increasing development of new storage facilities, especially those that provide what is referred to as high-deliverability service. This type of storage facility, which supports rapid transfer of inventories during peak-demand periods, provides transporters and their customers greater assurance that peak-day demands may be met. New and improved storage facilities also give pipeline companies the ability to offer services that integrate storage availability with market hub services and interconnections.

Deliverability refers to the volumes of natural gas that may be transferred at a designated point on the transportation network. The specific level of deliverability is normally measured in terms of peak-day capability and is a function of facility (system) design, which itself is premised upon actual or estimated market demand requirements. In this chapter, the discussion of pipeline deliverability refers to a summary measure of estimated pipeline capacity at regional and/or State boundaries. Deliverability from storage represents a volume that may be transferred to the pipeline network on a peak day to supplement the pipeline capacity serving the regional market.

This chapter addresses recent and proposed changes in the capability of the interstate pipeline network to deliver natural gas to local distribution companies and other customers. It also discusses the altered role of underground storage and how it has become strategically tied to the operations and marketing of market hub services. Lastly, in recognition of the fact that the increasing demand for natural gas must be delivered, in part, by an aging pipeline infrastructure, Federal and State reactions to pipeline safety concerns are also addressed.

Figure 14. Pipeline Capacity Increased by 14 Percent Between 1990 and 1994



To Region	Capacity Utilization Rates From Region								
	Western	Southwest	Central	Midwest	Northeast	Southeast	Canada	Mexico	Overall
Western									
1990	--	90	54	--	--	--	78	--	84
1994	--	63	79	--	--	--	81	--	71
Southwest									
1990	--	--	58	--	--	60	--	NA	69
1994	--	--	79	--	--	60	--	5	64
Central									
1990	78	49	--	90	--	--	75	--	56
1994	0	56	--	75	--	--	95	--	67
Midwest									
1990	--	--	72	--	56	64	84	--	64
1994	--	--	63	--	45	68	89	--	71
Northeast									
1990	--	--	--	76	--	85	66	--	80
1994	--	--	--	66	--	77	78	--	73
Southeast									
1990	--	73	--	--	69	--	--	--	73
1994	--	68	--	--	75	--	--	--	68
Canada									
1990	--	--	67	79	--	--	--	--	79
1994	--	--	13	69	--	--	--	--	67
Mexico									
1990	11	11	--	--	--	--	--	--	11
1994	15	14	--	--	--	--	--	--	14

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

Sources: Energy Information Administration (EIA). **State Export Status:** EIA, Office of Oil and Gas, derived from Production and Consumption, *Natural Gas Monthly* (April 1995), and **Pipeline Capacity Utilization Rates:** EIAGIS-NG Geographic Information System, Natural Gas Pipeline State Border Capacity Database, as of August 1995.

Pipeline Expansions, 1991-1994

After a period of rapid growth in pipeline capacity, expansion of the system slowed in 1994, with only several small expansion projects completed during the year. About two-thirds of the expansions were to enhance deliverability from Canada, with most of the rest for service to the Northeast. Overall since 1990, interregional capacity on the interstate natural gas pipeline system has increased by more than 14 percent, or 10 billion cubic feet per day (Figure 14). (Interregional capacity is defined as the capability to deliver gas to regional distribution networks from supply areas as measured at regional boundaries.) The total cost of new pipeline development and expansion implemented during the period is estimated to be about $6.5 billion.[1]

- **The impetus for much of the capacity increase has been the demand potential in the West and Northeast markets as well as the development of new supplies in western Canada** and in the Central and Southwestern States of Utah, Colorado, and New Mexico. Capacity from Canada into the United States increased by 59 percent during the period.[2] Capacity from the Central to the Western Region also increased dramatically, 219 percent (Figure 14), while capacity from the Southwest to the West increased more modestly, 23 percent.[3]

- **Overall capacity usage rates on the expanded network remained about the same despite the 14 percent increase in capacity and some soft regional markets.** Annual average use of Canadian import capacity rose by almost 8 percent in 1994 from 1990 levels, increasing on all routes. Even with a downturn in the economy in the Western Region and a 47-percent increase in capacity, average capacity usage rates from Canada into the Western Region were 3 percentage points higher in 1994 than in 1990 (see table in Figure 14). The enhanced oil recovery market in California supported high average utilization rates (79 percent) on those pipelines extending from the Central Region to the Western Region.

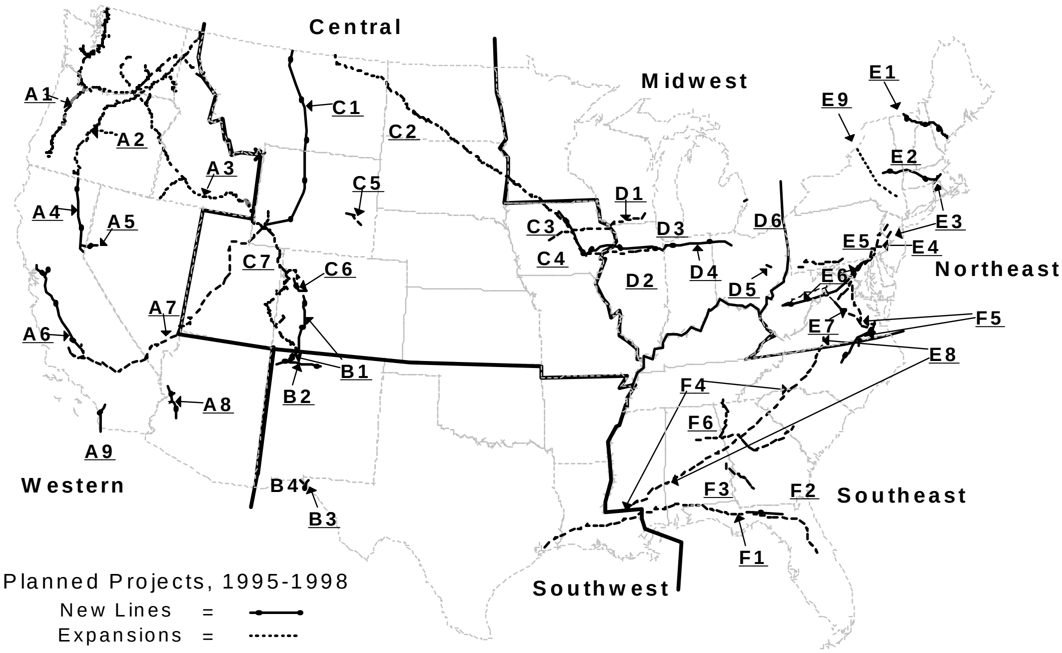
- **While capacity increased by 23 percent from the Southwest to the Western Region, these routes experienced the largest drop in capacity usage within the interregional network, with rates declining an average of 27 percent.** At least for the short term, there appears to be excess capacity on this portion of the network. Nevertheless, despite the economic downturn in California during the period, natural gas consumption in the State actually increased by 12 percent, while intrastate natural gas production decreased by 14 percent.[4] This production decrease, coupled with the recent indications that California's economy is in recovery, suggests an increased reliance upon available interstate capacity and a rebound in regional utilization rates in the future.

- **Although second to the Western Region, capacity expansions were also substantial into the Northeast Region.** Between 1990 and 1994, interstate deliverability into the Northeast grew by 19 percent, from 9.8 to 11.7 billion cubic feet per day (Figure 14). The vast majority of this expansion represented greater access to Canadian supplies. In contrast to the situation in the Western Region, most of the additional deliverability has been fully utilized, indicating that estimates of demand potential for natural gas in the region were near target. During the period, regional use of natural gas increased by 23 percent while local supplies, which were the equivalent of 14 percent of area consumption in 1990, fell to 10 percent in 1994.

- **Expected and actual growth in demand for natural gas as an electric generation fuel has spurred new construction.** A prime example is in the State of Florida. For instance, installed pipeline capacity on the Florida Gas Transmission system, which supplies almost all the natural gas to the eastern and southern parts of the State, increased by 15 percent, from 820 million cubic feet (MMcf) per day in 1990 to 943 MMcf per day at the end of 1994. Another 532 MMcf per day became operational in March 1995, amounting to an 80-percent increase since 1990.[5] For the Nation as a whole, natural gas usage by electric utilities increased by 7 percent between 1990 and 1994. Furthermore, the Energy Information Administration estimates in its *Annual Energy Outlook 1994* that expected growth in gas-fired electricity generating capacity between now and 2000 will require an additional 1.6 trillion cubic feet of gas supplies.

- **In the Midwest Region, demand increased by more than the additional deliverability into the region**. Whereas consumption increased by 600 billion cubic feet (Bcf) from the 1990 level, capacity additions totaled only 561 Bcf (on an annual basis). Although part of the increased demand was met by an 11-percent increase (31 Bcf) in regional production, the remainder was accommodated by greater use of existing capacity into the region. Capacity utilization rates increased from 64 percent in 1990 to 71 percent in 1994. The interstate pipeline system provided approximately 4 trillion cubic feet (Tcf) of the 4.3 Tcf consumed in the region in 1994.

Figure 15. Proposed Pipeline Construction Would Increase Interregional Capacity by 9 Percent by 1998



Map Key/Project Name	Design or Added Capacity (MMcf/d)	Estimated Costs (million $)
Western Region	**2,277**	
*A1--Northwest PL NWN	102	43
*A2--PGT Oregon Line (Exp)	91	46
*A3--Northwest PL System II (Exp)	62	63
A4--Tuscorora PL (New)	113	130
A5--Paiute Tahoe Lateral (Exp)	13	NA
A6--Mojave Extension (Exp)	475	466
*A7-- Kern River/Altamont (Exp)	452	308
A8--El Paso North/South (Exp)	469	62
*A9--San Diego G&E Project Vecinos	500	NA
Southwest Region	**904**	
*B1--TransColorado Pipeline (New)	300	184
B2--El Paso San Juan Triangle (Exp)	300	26
*B3--El Paso Samalayuca II (New)	300	57
*B4--Gas Co. Of New Mexico (New)	4	NA
Central Region	**2,152**	
*C1--Altamont Pipeline (New)	719	574
*C2--Northern Border PL (Monchy Exp)	213	NA
C3--Northern Border PL (Harper Exp)	263	NA
C4--NGPL Ventura/Harper (New)	850	NA
C5--KN Interstate - Casper Loop (Exp)	48	15
C6--Colorado Interstate Piceance (Exp)	37	9
C7--Questar Fidlar Station (Exp)	22	NA

Map Key/Project Name	Design or Added Capacity (MMcf/d)	Estimated Costs (million $)
Midwest Region	**1,888**	
*D1--Northern Natural PL (IA Exp)	108	NA
*D2--NGPL Chicago Line (Exp)	900	NA
*D3--Northern Border PL (IL/IN Exp)	[1]263	[2]370
D4--Crossroads PL (Oil Conversion)	250	32
D5--Tenneco/Southern Power (New)	117	7
*D6--Bluewater PL (New)	250	NA
Northeast Region	**1,632**	
*E1--Portland PL (New)	250	260
E2--Mayflower PL (New)	350	360
E3--TETCO/Algonquin PL ITP Project	112	121
E4--TETCO Philadelphia Lat (Exp)	30	8
E5--TETCO/Flex-X (West PA Exp)	100	NA
*E6--Tenneco Mid-Atlantic (New)	300	NA
E7--Columbia Gas Mid-Atlantic (Exp)	250	NA
*E8--Transco SE - Phase 2/3 (Exp)	165	NA
E9--Iroquois - Athens (Exp)	75	21
Southeast Region	**1,003**	
*F1-- FGT Phase IV	275	NA
F2--PenPipe Intrastate (New)	260	NA
F3--South Georgia PL (Exp)	41	27
F4--Transco Sunbelt Project (Exp)	146	NA
*F5--Winternet - CNG/TETCO (Mix)	400	375
F6--Southern Nat North End (Exp)	28	9

*Crosses regional boundary.

[1]The capacity of one pipeline segment is 263 MMcf per day, and after deliveries, capacity is only 133 for the subsequent segment.

[2]The total cost of C2, C3, and D3.

Exp = Expansion project; NA = Not available; MMcf/d = Million cubic feet per day; PL = Pipeline; Lat = Lateral; Mix = Expansion of existing facilities and new line.

Source: Energy Information Administration (EIA), EIAGIS-NG Geographic Information System, Natural Gas Pipeline Construction Monitoring Database, as of May 1995 compiled from industry trade press and filings with the Federal Energy Regulatory Commission.

Future Pipeline Expansions

As of July 1995, at least 40 new or expansion pipeline projects of varying sizes were under study, under construction, or before the Federal Energy Regulatory Commission (FERC) for consideration (Figure 15). Concerns about market expansion, surplus capacity in some areas, and the ability to recover costs have resulted in a slowdown in planned expansions. In 1994, several major proposed projects were either downsized, canceled, postponed, or withdrawn from the FERC approval process.[6] The backlog of expansions for the period, 9.9 billion cubic feet (Bcf) per day (41 projects), is 16 percent lower than the 11.8 Bcf per day (47 projects) planned for completion during the previous 4-year period from 1991 through 1994.[7] Still, if fully implemented, these projects would add 7.4 Bcf per day of pipeline capacity to current interregional capabilities by the end of 1998. This would represent an increase of 9 percent from the level at the end of 1994.

The development of a secondary market for capacity, development of market hubs, and other operational changes have improved the efficiency of the transmission system. The decline in planned capacity expansions is in part a reflection of these changes in the market. Still, projections of natural gas demand through 2000 show steady growth, with consumption increasing to 22 trillion cubic feet. The use of natural gas in electric power generation is a major component of this growth, and many of the proposed pipeline expansions have used service commitments on the part of electric utilities or cogeneration facilities as a key factor in supporting their bid for regulatory approval.

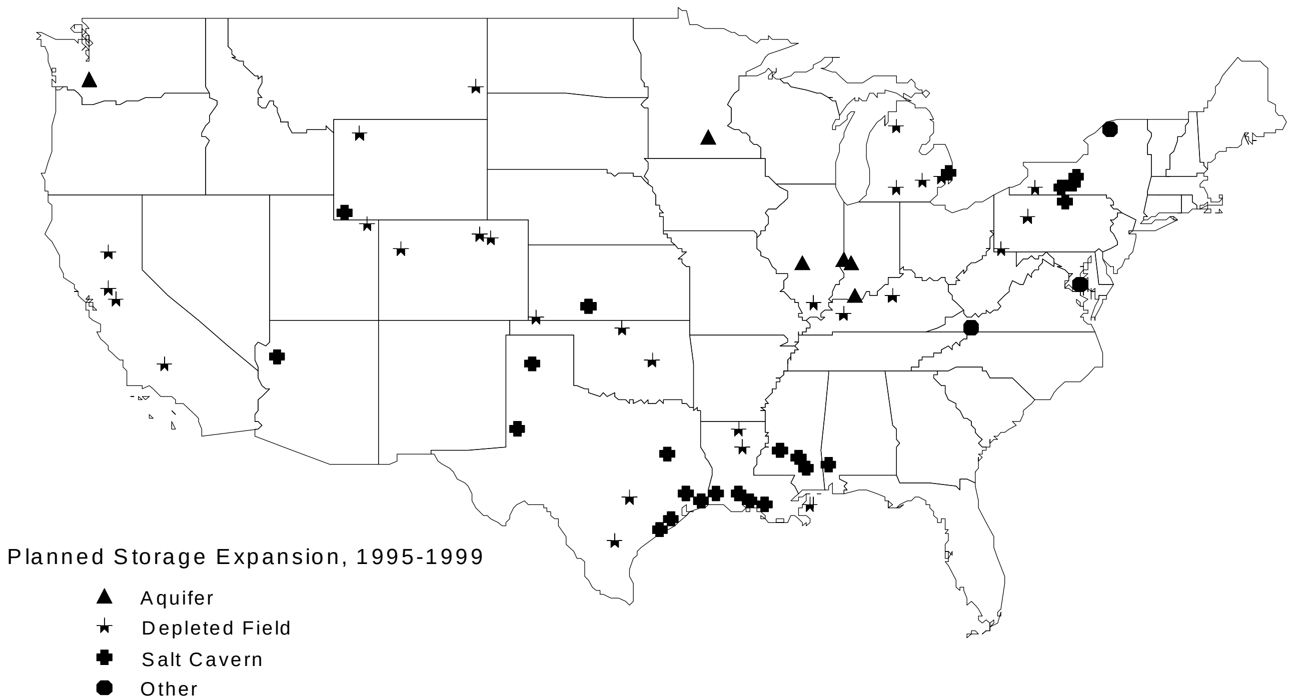
- **A growing factor in capacity expansions has been the drive to expand into new market areas and to offer new services**. Expansion of trunkline capacity was the larger component of capacity increases during the early part of the decade. Now capacity expansions are focusing on improving services within regions and developing operational flexibility to support new services. One example of this is the Winternet project, which is a joint effort of Texas Eastern Pipeline Company and CNG Transmission Company. This project will combine capacity expansion into a new market in northern North Carolina with the packaging of storage, peaking, and other services to support new customers there and in the Northeast. Texas Eastern, in affiliation with its corporate partner Algonquin Transmission Company, has also proposed a similar packet service (the Integrated Transportation Project) for customers in the Northeast.

- Growth of pipeline capacity into the Midwest Region will remain high during the next several years. The growing Chicago and northern Illinois markets are the target for two major proposed projects, which together represent 1.3 Bcf per day, or 87 percent, of the 1.5 Bcf per day of additional capacity slated for development into the region. (From 1991 through 1994, 1.5 Bcf per day was also put into service). The two are the Northern Border pipeline expansion project (0.3 Bcf per day), which has already been filed with FERC, and the Natural Gas Pipeline of America Company expansion proposal (0.9 Bcf per day). The latter project, while not yet before FERC, has generated enough interest among potential customers that the company may soon provide more specifications on project design. The Northern Border project also targets service expansion into the Indiana market via the Crossroads (oil pipeline conversion) project.

- **Planned expansion of capacity into the Northeast Region continues, but below the level of recent years.** Proposed capacity expansion into the Northeast Region currently amounts to 0.7 Bcf per day, 63 percent below the 1.9 Bcf per day completed from 1991 through 1994. Most of the planned expansion for the region represents added deliverability within the regional pipeline network (0.9 Bcf per day), again as pipeline companies are improving services and expanding markets within the region. Underlying this expansion is the increasing consumption of natural gas within the region. Long an area served primarily by fuel oil, the Northeast in recent years has seen a steady increase in the availability of natural gas. The expected growth market for the planned expansion is the industrial sector, especially cogeneration.

- **Proposed capacity expansion into the West is heavily dependent upon construction of the Altamont Pipeline.** The level of pending capacity additions into the Western Region through 1998 currently stands at 0.7 Bcf per day, compared with the 3.0 Bcf completed between 1991 and 1994 (Figure 14). A substantial portion (37 percent) of this proposed capacity expansion is represented by one project—the Kern River Pipeline expansion, which is predicated upon construction of the Altamont Pipeline, itself several times postponed because of changing market conditions and regulatory requirements. The Southwest Region also reflects a substantial decline in expansion activity during the next several years (compared with the period from 1991 through 1994). Proposed expansions into the Southwest are only 0.3 Bcf per day, compared with 2.8 Bcf per day added in the earlier period.

Figure 16. Peak-Day Deliverability from Storage Could Increase 23 Percent by 1999



Type of Storage Facility	Working Gas Capacity (Bcf)	Daily Deliverability (MMcf/day)	Type of Owner	Working Gas Capacity (Bcf)	Daily Deliverability (MMcf/day)
Depleted Field			**Independent**		
Existing 1994	3,168	53,196	Existing 1994	275	4,777
Planned 1995-1999	220	4,413	Planned 1995-1999	207	10,295
Total	3,388	57,609	Total	482	15,072
Salt Caverns			**Interstate Pipeline**		
Existing 1994	82	7,041	Existing 1994	2,160	34,091
Planned 1995-1999	124	11,100	Planned 1995-1999	78	2,683
Total	206	18,141	Total	2,238	36,774
Aquifers			**Intrastate Pipeline**		
Existing 1994	443	7,307	Existing 1994	137	3,586
Planned 1995-1999	1	0	Planned 1995-1999	34	1,570
Total	444	7,307	Total	171	5,156
Other			**Local Distribution Company**		
Existing 1994	2	185	Existing 1994	1,123	25,275
Planned 1995-1999	1	135	Planned 1995-1999	27	1,100
Total	3	320	Total	1,150	26,375
Total			**Total**		
Existing 1994	3,695	67,729	Existing 1994	3,695	67,729
Planned 1995-1999	346	15,648	Planned 1995-1999	346	15,648
Total	4,041	83,377	Total	4,041	83,377

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

Source: Energy Information Administration (EIA), EIAGIS-NG Geographic Information System, Natural Gas Underground Storage Database and Proposed Natural Gas Storage Projects Database, as of July 1995.

Underground Storage

The ability to store natural gas increases supply reliability during periods of heavy demand by supplementing pipeline capacity and serving as backup supply in case of an interruption in wellhead production. It also enables greater system efficiency by allowing more level production and transmission flows throughout the year. Currently, the industry has the capability to store approximately 8 trillion cubic feet of natural gas in at least 375 storage sites around the country. Almost half of this storage capacity is considered working gas storage that can be withdrawn to meet customer demand.

Underground storage inventories and operations have become key factors in today's natural gas market. With customers making their own arrangements to ensure supply reliability, they are more conscious of costs involved and are demanding new and more flexible storage services, which has also led to a marked increase in proposals for new storage capacity. Some of the trends and new developments within the storage industry include the following:

- **Inventory management practices have become more conservative as customers adjust to operating under Order 636**. By contrast to the past few years, the percentage of working gas capacity filled was higher at the beginning of the 1994-95 heating season than it had been the previous year and by September had exceeded the point reached at the same time in the 3 previous years.[8] With individual customers making their own decisions about inventory requirements, they may require, in aggregate, greater capacity than if pipeline companies, with their system-wide approach, still controlled storage levels. Weather-adjusted withdrawal activity in the 1994-95 heating season, however, resumed the upward trend seen from 1986 through 1992,[9] increasing by 52 percent from year-earlier levels.[10] Activity had declined during the 1992-93 and 1993-94 heating seasons, in part, because of the return to "more normal" winter weather. However, the larger decline in 1993-94 may also be attributed to cautious behavior by customers during their first heating season under Order 636.

- **New storage capacity has increased substantially.** Deliverability from storage has increased by 10 percent since 1990, and substantial additions are planned for completion by the end of the decade (Figure 16). Completion of these projects would increase working gas capacity by more than 9 percent from the level in 1994, and peak-day deliverability by 23 percent.

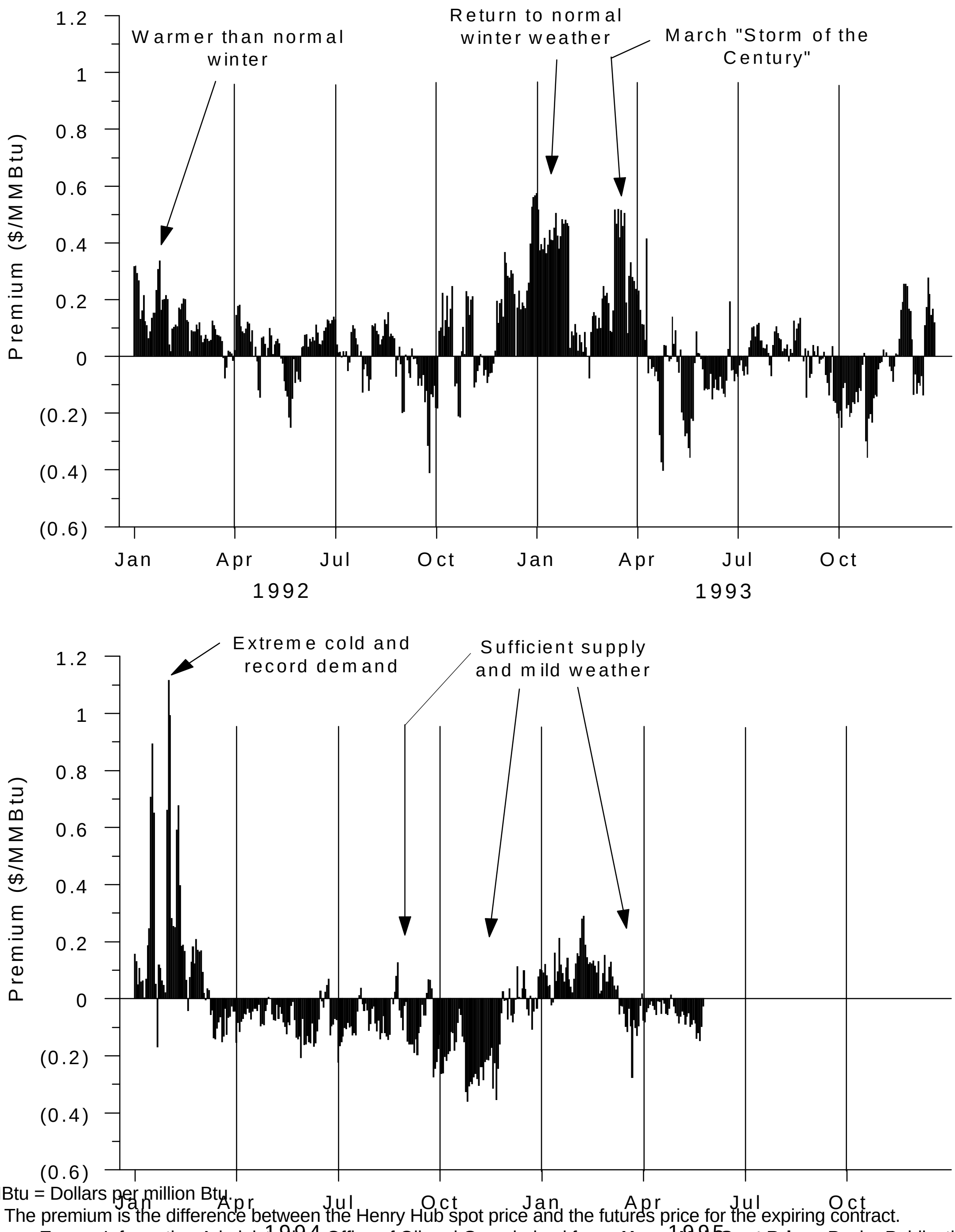
- **Most of the new storage development is high-deliverability storage, particularly salt cavern facilities (Figure 16).** Although salt cavern storage facilities usually have much less capacity than traditional storage sites in depleted gas and oil fields, they can be recycled quickly and can convert from injections to withdrawals in only a few hours, providing the flexibility for meeting market requirements. More than one-third of the 21 existing salt cavern storage operations have been brought on line since 1991, adding 29 billion cubic feet (Bcf) of working gas capacity and 3.1 Bcf per day of deliverability. Plans for additional high-deliverability projects account for 71 percent of the possible increase in peak-day deliverability by the end of the decade.

- **Independent storage operators have become the principal initiators of new storage projects (Figure 16).** While interstate pipeline companies currently manage most of the U.S. working gas storage capacity, they account for only 23 percent of the additions planned by 1999. In contrast, independent operators account for 60 percent of planned additions, with many developing salt cavern storage or other high-deliverability sites.

- **Several companies have asked the Federal Energy Regulatory Commission (FERC) to consider market-based rates for storage services from new as well as existing storage facilities**. As of September 7, 1995, FERC had approved 8 of the 20 submitted applications. All of the approvals pertained to services from individual storage facilities, as opposed to multiple facilities owned by one company. Six of the eight facilities are operational with the others in various stages of development. An applicant for market-based rates must demonstrate a lack of market power. This can be difficult except for those relatively small facilities in areas that already have ample storage alternatives. The spread of market-based rates may depend in large measure on the markets for released transportation and storage capacity.

- **Development of a secondary market for storage capacity has been quite limited.** As with transportation capacity, FERC requires that interstate storage providers allow their customers to release unused storage capacity. To date, however, shippers appear to be conservative about releasing capacity until they have more experience in the unbundled market.

Figure 17. Premium Value of Gas Reflects Supply Uncertainty and Weather Conditions



$/MMBtu = Dollars per million Btu.

Note: The premium is the difference between the Henry Hub spot price and the futures price for the expiring contract.

Sources: Energy Information Administration, Office of Oil and Gas, derived from: **Henry Hub Spot Price:** Pasha Publications Inc., *Gas Daily*. **Futures Price:** Commodity Futures Trading Commission, Division of Economic Analysis.

Value of Storage

The transparency of spot prices at a hub or market center allows the assignment of a daily market value to a company's stored gas near the hub or market center. High-deliverability salt cavern storage allows the quick release of this gas onto the market when the current market value rises. The location of the storage site near a hub or market center increases the chance that the willing seller of gas from storage will find a willing buyer. When spot prices fall, the company with flexible storage capability can inject the relatively inexpensive gas into its facility with the expectation that it can release some of this gas onto the market when prices subsequently rise. This type of inventory management is likely to gain in importance as the industry attempts to reduce cost and increase profitability through a better understanding of the value and strategic use of gas in storage.

- **The value of stored gas varies greatly over time as market conditions change.** A useful way to examine how the value of stored gas changes over time is to take the difference between the daily spot price and the settlement price of the nearby month futures contract at the Henry Hub. This difference is referred to as the premium value of stored gas near the Henry Hub. Similar premium values could be calculated for storage near other hubs or market centers.[11] If the premium is large and positive, as in early 1994 when it exceeded $1.00 per million Btu (Figure 17), it suggests that there is a high value associated with having gas in storage. When it is negative and large (in absolute value), as it was from mid-March 1995 to mid-June 1995, it suggests that supply is more than adequate. The spot price subsequently fell by more than $0.10 in late June after having remained relatively stable since mid-April. This price decrease is consistent with the ample supplies suggested by the low premium values.

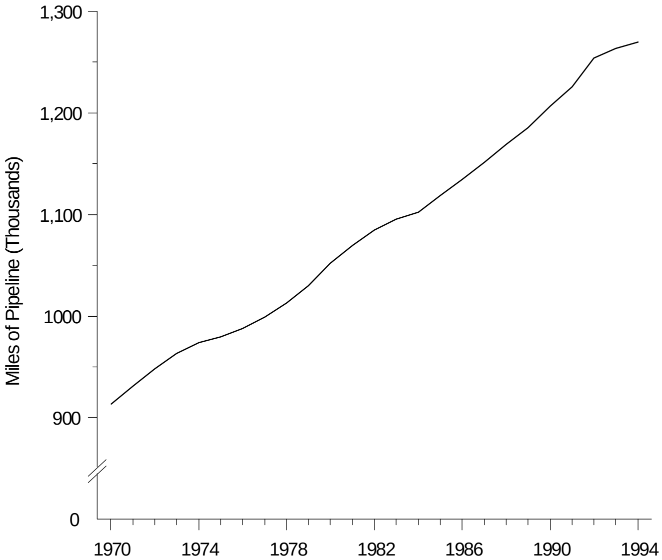
- **Stored gas has its greatest value during periods of extreme winter weather.** During the past 4 years, the premium value of stored gas has varied from $-0.41 to $1.12 per million Btu (Figure 17). Beginning in late December 1992 and extending into January 1993, there was a consistent premium of more than $0.35 per million Btu associated with stored gas, marking the return of normal winter weather after unseasonably warm winters in the previous years. The premium dropped until the March 1993 "Storm of the Century" when the premium soared to more than $0.50 per million Btu, once more indicating the high value associated with having stored gas available when the gas industry is under stress. Accordingly, the highest premiums were registered during the extreme cold spell of late January and early February 1994. High premiums, however, do not persist as the industry quickly responds to market conditions and changes in the weather. Thus, a period of possible shortage issoon followed by a period of possible surplus. In such a market, flexible storage allows a company to take advantage of changing market conditions.[12] This type of strategic behavior is also possible for companies that have contract rights to such facilities and have contracts that allow for flexible use.

- **Location of storage near hubs or market centers provides customers with a daily benchmark of storage values.** Customers can then determine both the value of their ready supplies of gas and also how this value has changed over time. If customers have a swap arrangement to hedge the price risk of the stored gas, they will know how this position is changing over time. They can anticipate payments or receipts based upon the quarterly or monthly balancing of swap arrangements.

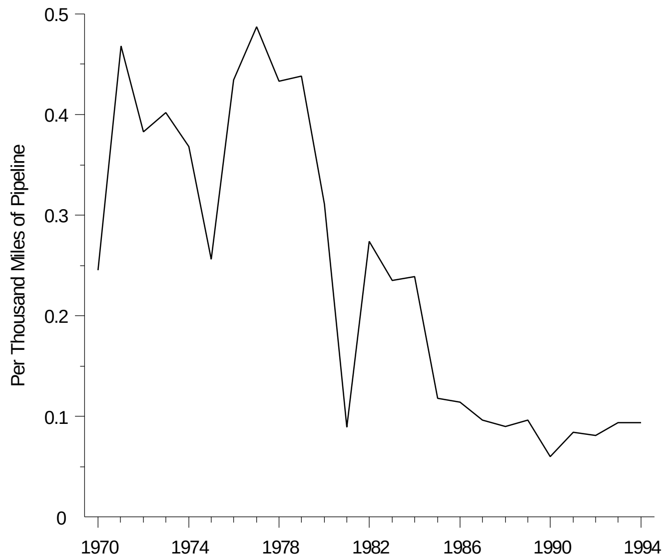
- **Storage capacity appears to be more than adequate to serve customer needs even on the coldest day of the year.** One crude measure of this is the amount of working gas in place at the end of the heating season, which has not been below 1.5 trillion cubic feet in 13 of the past 16 years. An equally important, and perhaps more telling indicator, however, is the rate at which this gas can be delivered into pipeline systems even on the coldest day. The capability to deliver gas into pipelines has increased by 10 percent during the 1990's, from 61.7 billion cubic feet (Bcf) per day in 1990 to 67.7 Bcf in 1994. Moreover, the increased number of salt storage facilities has improved the flexibility of storage operations. Salt storage operators can inject and withdraw throughout the year and quickly shift from one mode to another. Thus, not only do gas supplies in storage appear to be sufficient but also the capability to deliver these supplies appears to have improved. Furthermore this capability is expected to increase with the completion of new and expansion projects planned by 1999 (see previous section).

Figure 18. Pipeline Safety Has Improved

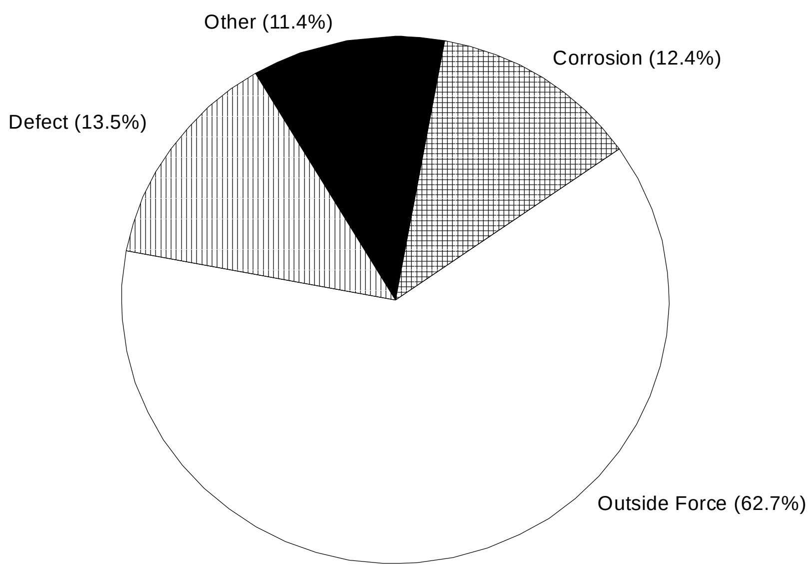
Natural gas pipeline miles have grown steadily . . .



. . . While the number of fatalities and injuries has declined



Most incidents since 1970 have been caused by outside forces



Total Incidents 1970 - 1994 = 25,719

Note: Includes data for both distribution and transmission systems. Incidents include fatalities, injuries, and property losses.

Source: U.S. Department of Transportation, Office of Pipeline Safety. **1970-1991:** *Annual Statistics on Pipeline Safety in the U.S. 1970-1991*. **1992-1994:** Office of Pipeline Safety.

Pipeline Safety

Most of the Nation's vast pipeline system was put in place more than 30 years ago. The aging of the system, combined with the increasing urbanization of the country and several pipeline accidents, has intensified concern about pipeline safety issues. In 1994 more than 200 natural gas pipeline reportable incidents occurred in the United States, resulting in 21 fatalities and 112 injuries. It should be noted, however, that most of these incidents were the result of damage by outside forces (Figure 18) rather than as a result of inadequate construction or operation practices.

A major explosion on the Texas Eastern Gas Transmission pipeline in Edison, New Jersey, in March 1994 prompted an extensive investigation of the event and of pipeline safety in general. Separate investigations were conducted by the National Transportation Safety Board and the Department of Transportation's Office of Pipeline Safety and a coalition of industry associations, which led to several recommendations.

- **The National Transportation Safety Board[13] report confirmed that the probable cause of the March rupture was damage to the external surface of the pipeline by excavation equipment of a nearby asphalt manufacturer.** The Board recommended that the Office of Pipeline Safety:

  — Require automatic or remote-operated mainline valves on high-pressure pipelines in urban and environmentally sensitive areas to provide for rapid shutdown

  — Develop "toughened standards" for new pipelines, especially those installed in urban areas

  — Eliminate exceptions for marking pipeline routes in densely populated areas

  — Develop standards for periodic internal inspection of pipelines.

  In addition to installing new valves, Texas Eastern was advised to document aircraft overflight observations of excavation activity adjacent to its pipelines, and distribute educational materials on pipeline safety to residents and workers near the pipelines' rights-of-way. Trade associations were urged to pass these recommendations on to their members.

- **The Office of Pipeline Safety report[14] concluded that the March 1994 explosion was an isolated occurrence.** The report was a cooperative effort with the New Jersey Board of Public Utilities and consisted of a comprehensive inspection of the six major natural gas transmission pipelines with operations in New Jersey.[15] The report concluded that the six pipeline companies are substantially in compliance. However, several issues were identified that require further review or action, including consideration of:

  — Backup systems for power assisted valve operators

  — Criteria for the installation of automatic or remote valves

  — Increased use of internal inspection device technology to help determine the presence of external and third-party damage to the pipeline

  — Evaluation standards for internal inspection device data ("smart pigs").

- **The U.S. Congress is currently considering pipeline safety legislation that includes a reduction in funds, as well as a 4-year risk management demonstration project by pipeline companies.** This proposed legislation (H.R. 1323) would reduce funding for the Office of Pipeline Safety, put a 6-percent limit on any future funding increases, and direct the Office to conduct a risk management demonstration project allowing pipeline companies to fashion individual safety programs.

The Department of Transportation's Research and Special Programs Administration (RSPA) is responsible for implementing safety legislation for oil and gas pipelines, such as the Pipeline Safety Act of 1992. The Act requires electronic inspection devices (smart pigs) in new and replacement lines, periodic inspections of lines in high-density areas, curb-side excess flow valves for residential service, and notification to customers of any customer-owned lines and of the hazards of failing to maintain the lines. RSPA issued a Final Rule in April 1994 on requirements for the use of smart pigs for new lines. A Final Rule on periodic inspection of existing lines is expected in late 1995.

Chapter 4 Endnotes

1. Energy Information Administration, Office of Oil and Gas Natural Gas Construction Monitoring database, as of May 1995, based on estimates of pipeline construction costs in filings with the Federal Energy Regulatory Commission (FERC) or in trade press announcements.

2. All changes in capacity and utilization rates cited in this section are based upon data reported in the Energy Information Administration, *Capacity and Service on the Interstate Natural Gas Pipeline System 1990*, DOE/EIA-0556 (Washington, DC, June 1992) and the Energy Information Administration, EIAGIS-NG Pipeline Capacity database, as of May 1995.

3. Some of the 36-percent increase from the Central to the Southwest Region actually reflects additional deliverability directed toward the Western market.

4. Changes in State natural gas production and consumption levels are based on: Energy Information Administration (EIA), *Natural Gas Annual 1990*, DOE/EIA-0131 (Washington, DC, 1990); and EIA, *Natural Gas Monthly*, DOE/EIA-0130(95-08) (Washington, DC, August 1995). Production levels are based on reported marketed production, which include volumes prior to extraction of liquids; State consumption levels are represented by total natural gas deliveries to all consumers.

5. The State's overall increase in gas consumption has kept pace with the expansion of system capacity. From 1991 through 1994, consumption of natural gas in the State grew by 9 percent. Total capacity on all pipelines into the State in 1994 was being utilized at 86 to 90 percent, while the Florida Gas Transmission system alone experienced a 95-percent utilization rate.

6. Canceled projects include the Liberty pipeline project (182 million cubic feet per day) in New York State and the Sunshine project (330 million cubic feet per day) into Florida. The Northwest Pipeline Company Expansion II was also downsized significantly in April 1994.

7. See Energy Information Administration, *Capacity and Service on the Interstate Natural Gas Pipeline System 1990*, DOE/EIA-556 (Washington, DC, June 1992), p. 11.

8. Energy Information Administration, *The Value of Underground Storage in Today's Natural Gas Industry*, DOE/EIA-0591 (Washington, DC, March 1995), Figure 19, p. 29.

9. Energy Information Administration, *The Value of Underground Storage in Today's Natural Gas Storage Industry*, Figure 18, p. 28.

10. Based on data from Energy Information Administration, Form EIA-191, "Underground Gas Storage Report." Monthly withdrawals have been adjusted for weather by subtracting the estimated influence of heating degree days from withdrawals. The estimated influence is obtained by regressing withdrawals on heating degree days. Weather-adjusted withdrawals for the 1994-95 heating season were 238 billion cubic feet (Bcf) in November, 232 Bcf in December, 319 Bcf in January, 324 Bcf in February, and 286 Bcf in March. Withdrawals were 97 Bcf higher than in the 1986-87 heating season, in contrast to 90 Bcf higher in 1992-93 and only 64 Bcf higher in 1993-94.

11. Because the futures contract price includes both the cost of storage and the opportunity cost of purchasing and storing gas, positive values for this difference represent an estimate of the return for stored gas over and above these costs. Moreover, if the futures price exceeds the cash price, that is the premium is negative, by more than the cost of storage and the cost of money, a risk free return can be gained by borrowing money and then purchasing and storing gas with this money, and then delivering the gas under a futures contract. Thus, the absolute value of the lowest value for the premium provides an upper bound estimate of the short-term (less than 1 month) cost of money and storage in the gas industry. 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). For a discussion of the implicit cost of storage and the cost of money in the futures price, see N. Kaldor, "Speculation and Economic Stability," *The Review of Economic Studies*, Vol 7 (1939), pp. 1-27 and Jeffrey Williams, "The Economic Function of Futures Markets" (Cambridge University Press, Cambridge, 1986).

12. For example, when the futures price exceeds the cash price by more than the cost of storage and the cost of money, a guaranteed profit can be obtained by opening a position to sell gas under a futures contract in the futures contract market, purchasing gas with borrowed money, injecting this gas into storage, and then delivering the gas under the futures market. On the other hand, when the cash price exceeds the futures price, a guaranteed profit can be made by withdrawing the gas from storage, selling it on the market near the cash price, and then opening a position on the futures contract to buy gas. In this latter instance, the high-priced supplies are sold and replaced with less expensive future supplies. Of course, any additional costs from such transactions

would need to be counted as well. For further discussion of this and related issues, see: John H. Herbert, "Improving Competitive Position with Natural Gas Storage," *Public Utilities Fortnightly* (October 15, 1995), pp. 32-35.

13. National Transportation Safety Board, "Pipeline Accident Report: Texas Eastern Transmission Corporation Natural Gas Pipeline Explosion and Fire, Edison, New Jersey, March 23, 1994" (Washington, DC, January 1995).

14. U.S. Department of Transportation, Office of Pipeline Safety, *Comprehensive Inspection Report of New Jersey Interstate Natural Gas Transmission Pipeline Operators* (Washington, DC, February 1995).

15. The six pipeline companies include Algonquin, Penn-Jersey Pipeline, Columbia Gas Transmission, Tennessee Gas Pipeline, Texas Eastern Gas Transmission, and Transcontinental Gas Pipe Line. The latter four are among the largest in the United States with operations and facilities located in upwards of 15 States. "Top 100 Natural Gas Pipelines," *Pipeline and Gas Journal* (September 1994), pp. 46-52.

5. End-Use Markets

End-use consumption of natural gas continues to grow, but has not yet returned to the level of the early 1970's when it reached 19.9 trillion cubic feet (Tcf). The removal of legislative restrictions to the use of gas and regulatory restructuring have brought significant changes to the natural gas industry in the past decade. End-use consumption in 1994 was 18.9 Tcf, significantly above the recent low of 14.8 Tcf in 1986.[1] Natural gas is now seen as a readily available fuel whose environmental qualities make it more attractive than other hydrocarbon fuels.

The industrial sector is the largest end-use consumer of natural gas. Gas consumed by nonutility generators (NUG's) to produce electricity is included in this sector. Increases in NUG consumption have played a part in the greater use of gas by industrials. In electric utilities, natural gas is used as a marginal fuel for the generation of electricity. Thus consumption of gas in this sector is very sensitive to the price and availability of other fuels, such as its close competitor, fuel oil, even when there is little change in the total amount of electricity generated.

In both the residential and commercial sectors, the predominant use of natural gas is for space heating. Thus, gas consumption in these sectors is particularly sensitive to weather patterns. Energy efficiency gains, both in gas appliances and in building construction, have tended to dampen growth in gas consumption that might otherwise be expected from increases in the number of customers in these sectors.

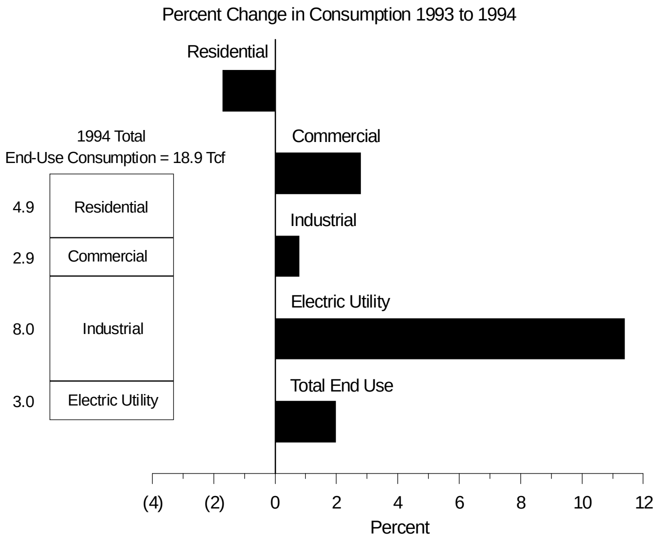
Space-heating requirements in all sectors result in a highly seasonal pattern of natural gas consumption that affects all other aspects of the industry, from production and storage to contracting considerations and price movements on the natural gas futures market. However, the degree of variation differs significantly by sector. For example, the average difference between the lowest and highest monthly consumption during the period from 1989 through 1993 was approximately 300 billion cubic feet (Bcf) in the commercial sector and 690 Bcf in the residential sector. In contrast, this difference was approximately 110 Bcf in the industrial sector and 190 Bcf for electric utilities. Unlike in the other sectors, electric utility consumption is at its highest in the summer when utilities can take advantage of off-peak conditions in the natural gas market.

Natural gas prices in all segments of the industry fell substantially during the past decade. Between 1985 and 1994, the real average wellhead price (in 1994 dollars) dropped by $1.52 per thousand cubic feet (Mcf) (45 percent) and the average "citygate" price, the price paid by local distribution companies for gas delivered to their systems, dropped by $1.93 per Mcf (39 percent). Average end-use prices also fell during the period to varying degrees in the different sectors. Residential and commercial customers, who have limited options for the high-quality gas service they require, saw prices drop by $1.77 per Mcf (22 percent) and $1.92 (26 percent), respectively, during the period. Electric utilities saw the greatest decline—$2.47 per Mcf (52 percent). The price change for industrial users is not in this comparison because of the extensive changes in their purchasing patterns during the period. Available data on industrial prices represent only onsystem sales, that is gas purchased from local distribution companies. The share of onsystem deliveries to industrial customers dropped from 69 percent in 1985 to only 22 percent in 1994.

End users are likely to face more changes during the next few years not only in gas service, but in electricity as well. Many States are considering or have already implemented Order-636-style unbundling of gas services at the local distribution company level. Also, both Federal and State regulators are exploring changes in electricity regulation that could affect the market for gas used in electricity generation. As energy providers realign themselves under the new regulatory environment, they will offer services to end users that can be more specifically tailored to the customers' needs. These market developments could encourage the formation of new companies that offer both gas and electric services.

Figure 19. End-Use Consumption Reached its Third-Highest Level in 1994

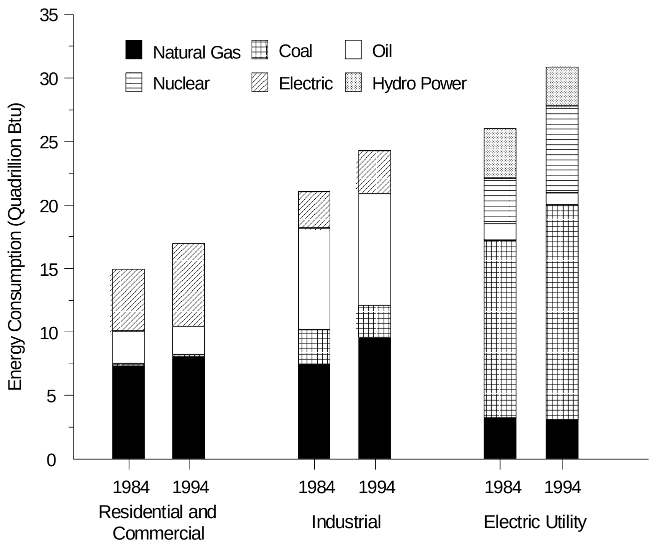
The electric utility sector shows the greatest change between 1993 and 1994



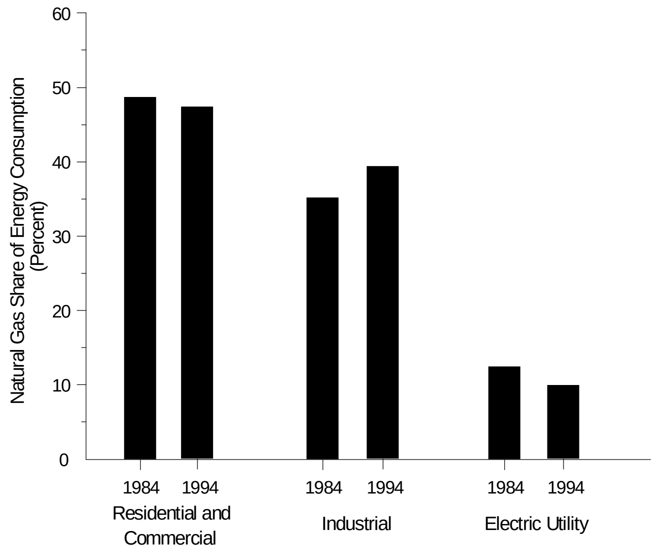
End-Use Prices
(Dollars per Thousand Cubic Feet)

Year	Residential	Commercial	Onsystem Industrial	Electric Utility
1992	5.89	4.88	2.84	2.36
1993	6.16	5.22	3.07	2.61
1994	6.41	5.43	3.05	2.27

Natural gas has been an important energy source during the past decade . . .



. . . But has increased its share only in the industrial sector



Notes: Data for 1994 are preliminary. Total may not equal sum of components because of independent rounding. Industrial sector prices are for onsystem deliveries only. The onsystem share of total industrial natural gas consumption was 30 percent in 1992 and 1993, and 22 percent in 1994. The following notes apply to the bottom left graph. Energy consumption is total energy consumption for the electric utility sector and net energy consumption (excludes electrical system energy losses) for other sectors. Coal for the combined residential and commercial sectors is less than 0.21 quadrillion Btu (QBtu) each year. Coal for the industrial sector includes net imports of coal coke, which is less than 0.03 QBtu each year. Hydro power for the industrial sector is less than 0.04 QBtu each year. Hydro power for the electric utility sector includes geothermal, which is less than 0.20 QBtu each year and other, which is less than 0.02 QBtu each year.

Sources: Energy Information Administration. **Natural Gas Consumption and Prices:** *Natural Gas Monthly* (July 1995). **Energy Consumption:** Office of Oil and Gas, derived from: *Monthly Energy Review* (July 1995).

End-Use Consumption and Price

End users consumed 18.9 trillion cubic feet (Tcf) of natural gas in 1994, the highest level since 1974. End-use consumption in 1994 was 2 percent higher than in 1993 and was largely driven by greater use of natural gas by electric utilities (Figure 19). Increased economic activity in 1994 led to somewhat higher consumption in the commercial and industrial sectors as well, while warmer-than-normal weather overall (despite the deep chill of January and February) resulted in a slight decline in residential consumption.

The electric utility sector had the greatest percentage change in average annual prices of all the sectors between 1993 and 1994. As the national average wellhead price declined 10 percent in 1994, the delivered price of natural gas to electric utilities fell 13 percent, to $2.27 per thousand cubic feet (Mcf). In contrast, prices rose 4 percent in 1994 in both the residential and commercial sectors, reaching $6.41 and $5.43 per Mcf, respectively. These increases may reflect the cost associated with implementation of Order 636.

Consumption patterns during early 1995 differed from those in 1994, perhaps reflecting the effect of the cold weather in January and February 1994. Residential and commercial consumption in the first 4 months of 1995 were down by 8 and 5 percent, respectively, compared with the same period in 1994. Industrial and electric utility consumption, however, increased by 7 and 19 percent, respectively.

- **Electric utility consumption increased 305 billion cubic feet (Bcf), or 11 percent in 1994—the first notable increase in this sector since 1989.** Consumption in 1994 of 3.0 Tcf was spurred not only by the large drop in natural gas prices and an increase in economic activity, but also by weather conditions. Lack of rainfall, particularly in the Northwest, reduced the availability of hydro power for electric generation. Hydroelectric generation declined 8 percent from 1993 to 1994 while gas-fired utility generation increased 12 percent,[2] contributing to the overall 1-percent increase in power generation by electric utilities.

- **Consumption in the industrial sector reached 8.0 Tcf in 1994, replacing 1993 as the third-highest level recorded.**[3] However, the increase was only 61 Bcf, or 1 percent above the level in 1993. Consumption of natural gas by nonutility generators (NUG's) for electricity production is included in the industrial sector data. These end users had a steady increase in consumption of 200 Bcf each year from 1990 through 1993,[4] the latest year for which separate data are available. NUG consumption of natural gas was 2.0 Tcf in 1993. Data through April 1995 show that industrial consumption grew by 7 percent compared with the same period in 1994.

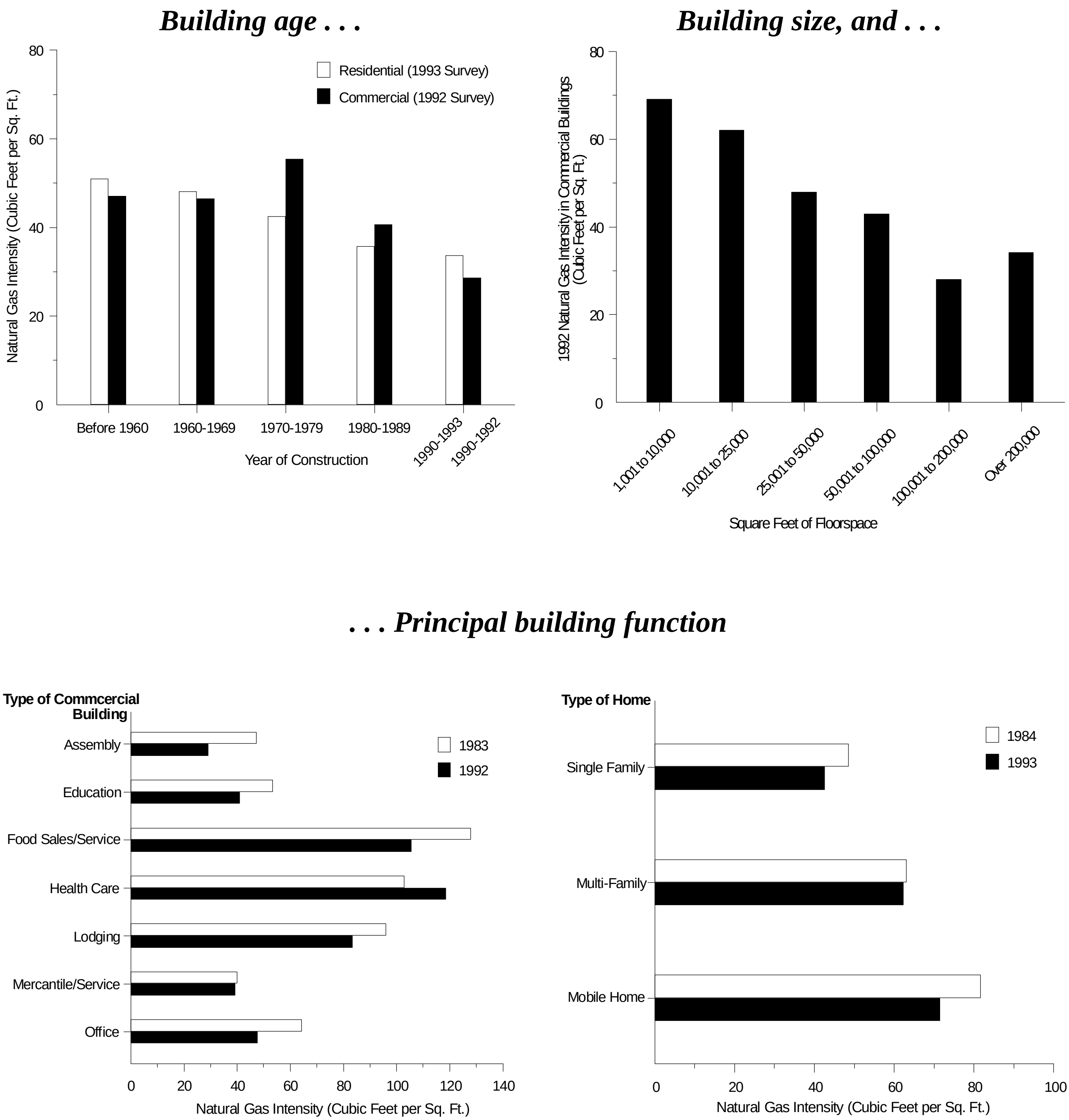
- **The different movement in residential and commercial consumption in 1994 was unusual** in that gas is largely used for space heating in both sectors, and one would expect them to be similarly influenced by weather. While the severe cold in January 1994 resulted in record monthly consumption in both sectors, warmer-than-normal weather later in the year reduced the need for gas for space heating. Residential consumption declined 2 percent in 1994 to 4.9 Tcf, but commercial consumption increased 3 percent to 2.9 Tcf. The growing economy may have contributed to the increase in this sector particularly during the spring and summer.

- **Use of compressed natural gas for vehicular transportation reached 960 million cubic feet (MMcf) in 1993.** This was significantly higher than the 270 MMcf used in 1990.[5] The number of fueling stations has also grown steadily, reaching 930 by the end of 1994.[6] For natural gas to become a more practical transportation fuel, several obstacles must be overcome: vehicle cost, driving range, fuel distribution, and safety questions.

- **Natural gas is an important source of energy for all types of end users, but during the past decade, it has increased its share of total energy consumption[7] only in the industrial sector (Figure 19).** Natural gas consumed in the residential and commercial sectors combined increased from 7.3 quadrillion Btu (QBtu) in 1984 to 8.0 in 1994. Yet during the same period, the natural gas share of energy consumption declined slightly, from 49 percent to 47 percent. Industrial energy consumption increased by 15 percent during the period, and natural gas use went from 7.4 QBtu to 9.5 QBtu, increasing its share from 35 to 39 percent. Increases in NUG use of gas contributed to this rise. In the electric utility sector, growth in total energy use of 19 percent between 1984 and 1994 was fueled mainly by coal and nuclear power, while the natural gas share fell slightly, from 12 to 10 percent.

End-use consumption of natural gas is projected to grow at an annual rate of 1.0 percent from 1994 through 2000.[8] This is significantly slower than the 2.4 percent annual growth from 1988 through 1994. Most of the growth is expected in industrial and electric generation uses. Conservation and efficiency improvements are expected to offset projected increases in the number of residential and commercial customers, dampening the rate of growth in these sectors.

Figure 20. Natural Gas Intensity in Residences and Commercial Buildings Is Significantly Affected by



Sources: Energy Information Administration. **Residential:** Office of Energy Markets and End Use, derived from: EIA-457, "Residential Energy Consumption Survey" for 1984 and 1993. **Commercial: 1983—**Office of Oil and Gas, derived from: *Commercial Buildings Energy Consumption and Expenditures 1983*. **1992—**Office of Energy Markets and End Use, derived from: revised estimates to EIA-871, "Commercial Energy Consumption Survey" for 1992.

Residential and Commercial Consumption

The predominant use of natural gas by residential and commercial customers is for space heating. In 1993, residential users consumed 3.6 trillion cubic feet (Tcf) of gas, or 70 percent of their total gas consumption, for this purpose; while in 1992, 1.3 Tcf, or 61 percent, of commercial gas consumption was used for space heating.[9] Water heating ranks second in both sectors, accounting for 25 percent of the residential and 23 percent of the commercial gas consumption (in 1993 and 1992, respectively).

The use of gas for heating needs results in a highly seasonal pattern of consumption in these two sectors, which is a driving force in the seasonality seen in both production and storage withdrawals. However, meaningful changes in the amount of gas consumed by these users on an annual basis are determined more by the number of customers and the energy efficiency of existing housing and commercial buildings (and the gas appliances they contain) than by weather patterns. The measurement of natural gas intensity, or the amount of gas consumed per square foot of floorspace, is an indicator of efficiency in the residential and commercial sectors. An examination of the different types of residential and commercial buildings shows that natural gas intensities have declined, thus efficiency gains have been made in both sectors.

- **Commercial buildings constructed from 1990 through 1992 have an average natural gas intensity of 29 cubic feet per square foot.** This is about 40 percent less than that of buildings constructed before 1960 and about half that of buildings constructed during the 1970's (Figure 20). Residences built from 1990 through 1993 used gas at an average rate of 34 cubic feet per square foot—approximately one-third less than the intensity of those built before 1960. Such improvements may be the result of better construction techniques and the installation of more efficient gas furnaces in newer buildings.

- **Natural gas intensities in large commercial buildings are only about half the level in smaller buildings (Figure 20).** Natural gas consumption is approximately 60 to 70 cubic feet per square foot in commercial buildings with 25,000 square feet or less of floorspace, but is only approximately 30 to 35 cubic feet per square foot in the largest buildings (those with more than 100,000 square feet of floorspace).

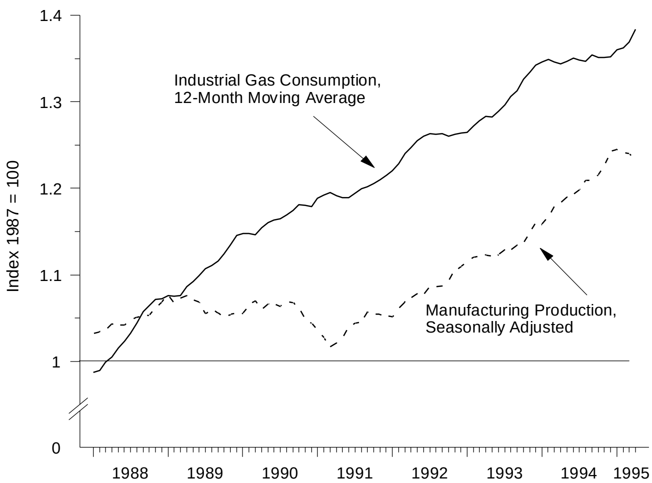
- **Natural gas intensities vary widely among the different types of commercial buildings, but most showed some improvement between 1983 and 1992 (Figure 20).** The greatest percentage declines in gas use per square foot came in buildings that are places of assembly (38 percent) and offices (26 percent). The only category of commercial building that increased its gas intensity was health care. Health care buildings consumed 199 cubic feet of natural gas per square foot of floorspace in 1992, replacing food sales and service as the highest intensity category.

- **In both single-family homes and mobile homes, gas use per square foot declined 12 percent between 1984 and 1993 (Figure 20).** Mobile homes, which had the highest energy intensity among the dwelling types in 1984 showed the greatest absolute change, with consumption declining from 82 cubic feet per square foot in 1984 to 72 in 1993. More improvements may be expected because of new Federal energy standards for mobile homes that went into effect in October 1994. Natural gas intensities also declined for multifamily dwellings during the period, but by only 1 percent. Weatherization efforts on the part of home owners and the replacement of old furnaces by new, higher efficiency units over time may help to explain the improvements shown here.

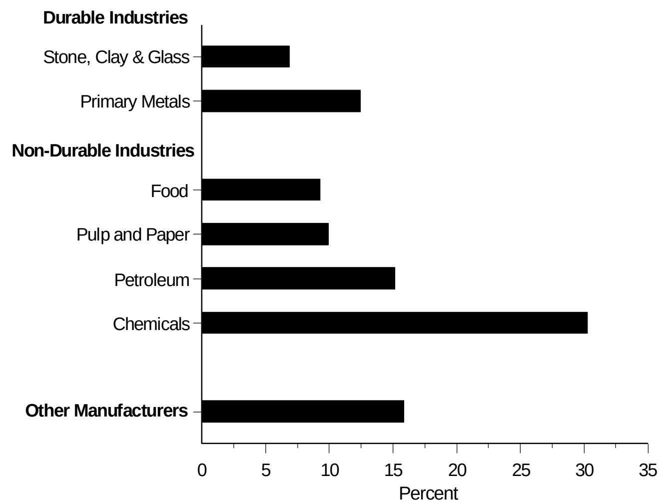
- **Gas remained the heating fuel of choice in new single- and multifamily housing units constructed in 1993**.[10] During that year, 66 percent of the new single-family homes and 52 percent of the units in new multifamily buildings were heated by gas. However, the choice of heating fuel varied significantly among the Census regions. For example, in 1993, half of the 456,000 single-family homes completed in the South Census Region were heated with gas, while nearly 90 percent of the 232,000 new homes in the Midwest Census Region were heated with gas. These data represent a large increase in the gas share of new home construction in the South Region (only 38 percent of the single-family homes built in 1989 were gas heated), yet the gas share in the South is still the lowest in the Nation. In the Midwest Region, the gas share has consistently been high, increasing from 85 percent of the new single-family homes built in 1989 to 88 percent in 1993.

Figure 21. The Industrial Users of Gas Are Diverse

Industrial gas consumption is driven by manufacturing activity

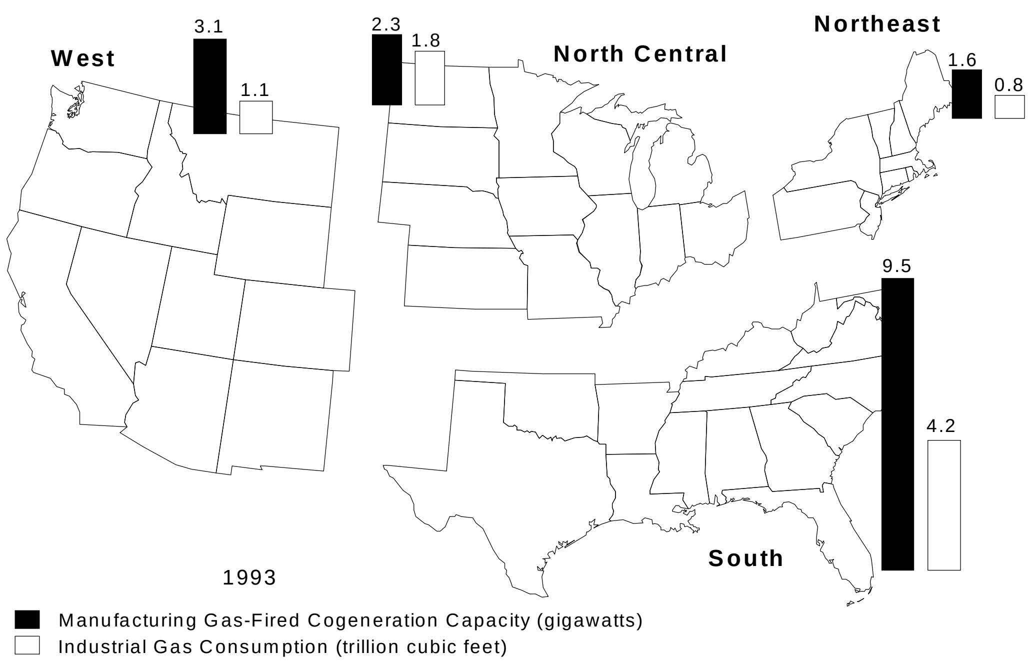


The largest manufacturing consumers of gas for heat and power are chemical plants



Estimated 1991 manufacturing consumption for heat and power = 5.8 Trillion cubic feet

Gas-fired cogeneration in the manufacturing sector is concentrated in southern States



Note: Manufacturing data are based on a sample that excludes small establishments, mining, agriculture, forestry, fishing, construction, and transportation establishments, and certain nonutility generating establishments.

Sources: **Natural Gas Consumption Index and Regional Consumption:** Energy Information Administration (EIA), Office of Oil and Gas, derived from: 1988-1992—*Historical Monthly Energy Review 1973-1992*, 1993-1994—*Natural Gas Monthly* (July 1995). **Manufacturing Industrial Production Index:** Board of Governors of the Federal Reserve System. **Manufacturing Consumption:** EIA, *Manufacturing Consumption of Energy 1991*. **Cogeneration Capacity:** EIA, Office of Coal, Nuclear, Electric and Alternate Fuels.

Industrial Consumption

In recent years more than 40 percent of the natural gas sold to end users in the United States has been delivered to industrial consumers. In 1994, industrial gas use totaled 8.0 trillion cubic feet (Tcf), a 1-percent increase over 1993. This level of industrial gas consumption represents a 20-year high and is the largest quantity of industrial gas deliveries since 1974 when industrials used 8.3 Tcf of gas. Indications are that industrial gas use continued to grow during the first part of 1995. Preliminary data show that 1995 consumption was nearly 7 percent higher than in the same period of 1994.

- **Industrial consumption of natural gas generally follows the trend in industrial activity[11] (Figure 21).** For the period from March 1991 (the bottom of the last recession[12]) through March 1995, the seasonally adjusted indices of industrial gas consumption and manufacturing industrial production increased annually by 5.0 and 5.1 percent, respectively. Because different manufacturing activities use different proportions of gas in their production processes, the relationship between manufacturing output and gas consumption may change. Such changes can be caused by fuel switching, variations in output levels, and differential rates of improvements in energy efficiency. Price competition among fuels for heat and power uses is also very important in determining the amount of gas consumed for these purposes. For many years, the relative competitiveness of gas could be observed by looking at the costs of pipeline and distribution company gas deliveries to industrial establishments. However, because the restructuring of the natural gas industry now allows nearly 80 percent of industrial gas consumers to purchase gas from other suppliers, these data no longer reliably indicate the price competitiveness of gas to large industrial users. In 1994, the average price of gas delivered to smaller industrial customers who purchase onsystem gas supplies was $3.05 per Tcf.

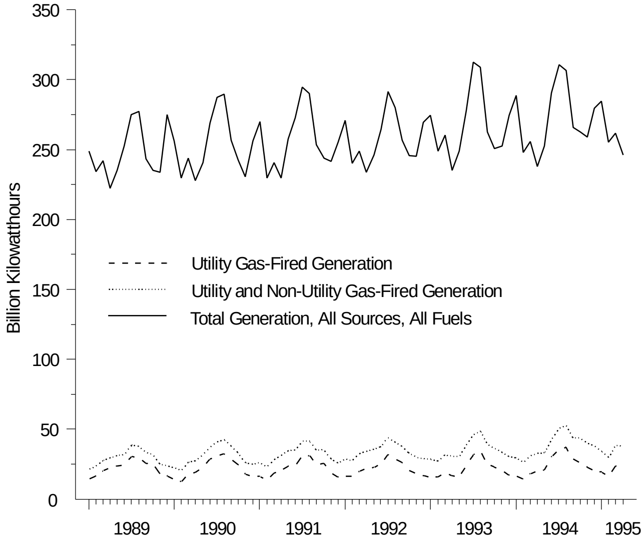
- **About 90 percent of the natural gas consumed in manufacturing is used to produce heat and power for industrial process uses.**[13] Natural gas is used extensively in both the durable and the nondurable industries. In 1991, the nondurable manufacturing establishments that used the greatest amounts of gas for heat and power were chemical manufacturing and petroleum refining establishments (Figure 21). However, both the primary metals and the stone, clay, and glass industries (durable goods industries) also consumed large quantities of natural gas. Manufacturers used the remaining 10 percent of their natural gas deliveries as raw materials, or feedstocks, for their products. For example, feedstocks are used in the production of chemicals and fertilizers. Restructuring of both the natural gas and the electricity industries could conceivably change industrial energy choices for heat and power by significant amounts if energy-intensive manufacturing customers get big new discounts for electricity purchases.

- **Some manufacturers use gas-fired cogeneration to produce electricity for internal consumption and sale to electric utilities**. Patterns of manufacturers' gas consumption may change when they install cogeneration. Cogeneration is a term used to describe a process whereby a single energy input, such as natural gas, is used to produce both electricity and useful thermal energy in the form of process heat. Since the passage of the Public Utility Regulatory Policies Act in 1978, national policy has encouraged cogeneration in energy-intensive industries.[14] Industries that use large quantities of natural gas to produce process heat, such as chemical manufacturing, are especially conducive to cogeneration applications. Because the electricity and the useful thermal energy (process heat) produced by a cogenerator are true joint products, it is not possible to attribute energy inputs directly to specific outputs in such establishments.

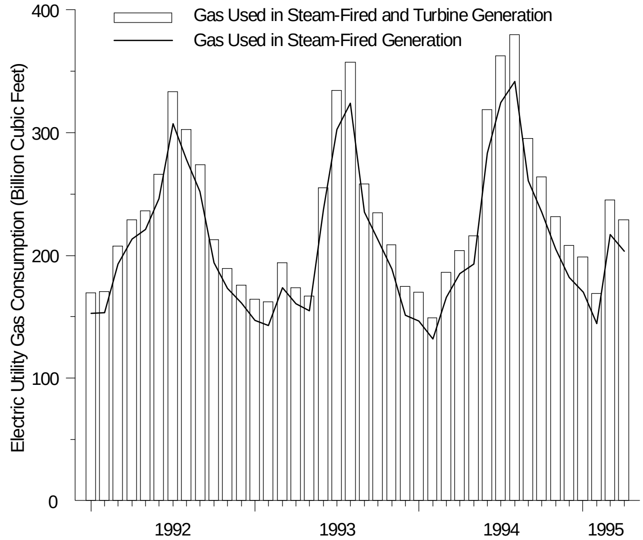
- **The regional distribution of gas-fired manufacturing cogeneration and industrial gas consumption suggests that both are influenced by similar factors.** The South Census Region has both the heaviest concentration of gas-fired cogeneration capacity in the manufacturing sector and consumes the greatest quantity of gas in industrial activities in general (Figure 21). In 1993, gas-fired manufacturing cogeneration accounted for about 27 percent of all nonutility generating capacity in the United States, while in the South, nearly 46 percent of this capacity was gas-fired.[15] The amount and size of gas-fired cogeneration capacity follows from this region's ability to attract gas-intense manufacturing because of the concentration of gas production in Texas, Oklahoma, and the Gulf Coast.

Figure 22. Natural Gas Consumption in Electric Generation Is Small But Critical

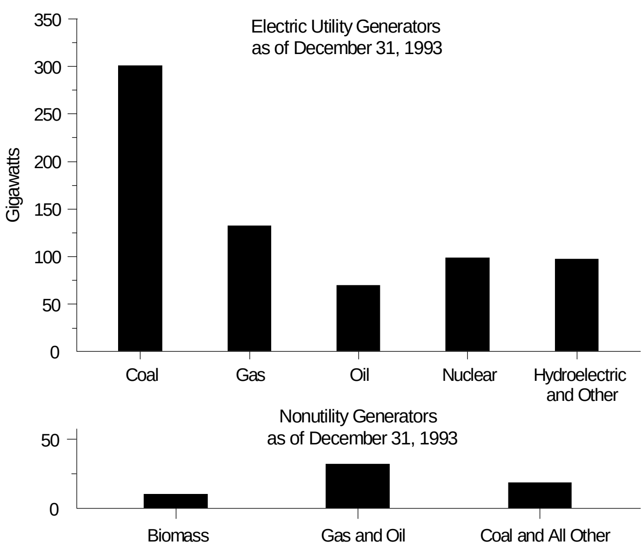
Gas-fired generation supplies only a small proportion of the electricity generated in the United States



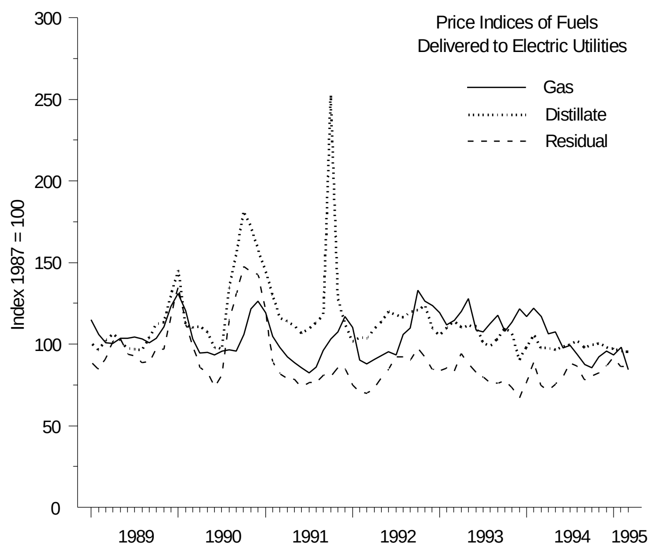
Most electric utility gas is consumed in steam generators



Fuel choice is constrained by existing generating capacity



As a fuel for electricity, gas competes directly with distillate and residual oils



Note: Gas consumed by utility-owned turbines may include a small amount of gas used in internal combustion engines. In the lower left graph, the scales on the axes are different.

Sources: Energy Information Administration. **Utility Electric Generation:** 1989-1992—*Historical Monthly Energy Review 1973-1992*, 1993-1994—*Monthly Energy Review* (July 1995). **Nonutility Electric Generation:** Office of Energy Markets and End Use, derived from: data collected by the Office of Coal, Nuclear, Electric and Alternate Fuels. **Utility Gas Consumption by Type of Generator:** *Electric Power Monthly*, various issues. **Generating Capacity:** *Electric Power Annual 1993*. **Utility Fuel Price Indices:** Office of Oil and Gas, derived from: data from Office of Coal, Nuclear, Electric and Alternate Fuels and *Electric Power Monthly*, various issues.

Gas Consumed in Electric Generation

The use of gas to generate electricity increased in 1994 but gas continues to supply only a small share of electricity production. The amount of gas used to produce electricity is a function of capacity type and fuel prices.

Two different technologies are used in gas-fired electric generators. The great majority of gas-fired capacity consists of boilers that produce steam to drive generators. These steam-drive generators are generally older plants and are concentrated in just a few States—Texas, California, New York, and Florida. The alternative technology is a combustion turbine.[16] Although turbines are much more widely distributed, they are generally smaller machines.

Legislation enacted in 1978 greatly affected natural gas consumption by electric utilities. The Power Plant and Industrial Fuel Use Act of 1978 (FUA) banned large, new gas-fired boilers. Although the ban on gas boilers was rescinded 10 years later, most of the gas-fired electric generators built since 1978 have incorporated turbine generators. FUA's companion legislation, the Public Utility Regulatory Policies Act (PURPA), laid the ground work for nonutility generators (NUG's) to enter the electricity industry. As a consequence, more than half of the new generation capacity added in recent years has been built by the NUG's. Nearly half of all NUG capacity is gas-fired.

- **Electric utility consumption of natural gas increased by 11 percent in 1994 even through utility electric output grew by only 1 percent.** Electric utilities increased gas consumption, in part to compensate for lower levels of hydroelectric generation due to drought conditions particularly in the Northwest. However, gas continues to fuel only a relatively small share, around 10 percent, of utility electricity output. Gas is used by a much larger proportion of NUG's; but even today, NUG's account for only about 9 percent of total U.S. generating capacity.[17] Thus, even though gas is the source of half of the NUG output, gas-fired generation from all sources is estimated to be about 15 percent of all the electricity produced in the United States in 1994[18] (Figure 22).

- **Nearly 90 percent of the gas consumed by utilities to generate electricity is burned in steam boilers (Figure 22).**[19] The average 1994 heat rate for utility gas-fired steam generators was 10,462 Btu per kilowatthour.[20] Utility systems that have gas-fired steam generators tend to use them under base and intermediate load conditions as well as for load following when they experience peaks.

  Utilities generally use turbines primarily to produce electricity to meet peak demands and for short-term replacement and emergency backup. As a result, these generators tend to be used fewer hours per year.

- **Utility gas-fired generators tend to be used much more heavily during the summer**. This seasonality reflects a combination of influences. Demand for electricity is sharply higher in the summer because of high cooling requirements in most regions of the United States. The winter peak in gas demand means that gas pipeline transportation capacity is more likely to be attractively priced and available to electricity generators in the summer. These counter-seasonal patterns result in much higher summer use of gas by electric generators.

- **Unless fuel-switching capability is built in, the stock of generators limits opportunities to vary the fuel used to produce electricity in the short term (Figure 22).**[21] At the end of 1993, 19 percent of the generating capacity owned by electric utilities was gas-fired while oil-fired capacity accounted for another 10 percent. Coal-fired generating capacity made up 43 percent of the capacity but supplied 56 percent of the 1994 production.[22]

- **Generally, natural gas and oil are the most flexible and highest variable cost generating resources; thus on most utilities' systems, they compete with each other at "the top of the dispatch order."**[23] In many fuel switchable generators, gas and oil products are direct substitutes for one another. Many boilers can burn either gas or residual fuel oil; many turbines can be switched between gas and distillate fuel oil. If gas pipeline capacity is available, the relative delivered prices of the competing fuels will generally determine which a utility burns. However, gas can have a competitive advantage when pollution abatement is a concern. The average price to electric utilities of natural gas, distillate, and residual oil in 1994 were $2.23, $3.99, and $2.41 per million Btu (MMBtu) respectively (Figure 22), while coal cost $1.36 per MMBtu. Gas and oil are used to fill any gap between the demand for electricity and electricity supplied from all other resources. Thus, unanticipated shifts in either electricity demand or the supply of other generating resources (e.g., nuclear or water power) may change the amount of gas used in electric generation.

Table 3. Comparing Milestones in Restructuring Industries

Event	Natural Gas Industry	Electric Industry
First step toward competition	Intrastate gas markets never federally regulated. Some large consumers in the interstate market started purchasing gas and pipeline transportation. separately—mid-1970's.	Short-term, inter-utility coordination trade at negotiated prices subject to regulated caps—1950's. Utilities file FERC rates with "up-to" cost-based formulas—early 1980's.
Explicit exceptions to cost-of-service rates appear	NGPA removes some natural gas price ceilings—1978. Pipeline companies use Special Marketing Programs to accommodate direct sales under price ceilings—early 1980's. FERC sets up blanket certificates to encompass them—1984.*	PURPA mandates purchases from QF's at utility's avoided cost—1978. FERC accepts power pool agreement with weighted aggregate price ceilings in lieu of individual company rates—1978. FERC recognizes competitive bidding for new capacity—1988.
Transition costs start accumulating	FERC relieves distributors of their obligations to purchase from pipeline companies without relieving pipeline companies of their obligations to purchase gas supplies—1984.	States subject new utility plants to review for large cost overruns—1970's. Avoided cost QF contracts start a PURPA boom—1984.
Transmission access proposed to dampen anticompetitive behavior and encourage competition	FERC encourages pipelines to make unbundled sales and provide open-access transportation—1985.	NRC requires transmission access for some licenses—1970's. FERC initiates transmission access conditions for merger approval—1988; and for market-priced power sales—1990. Energy Policy Act authorizes FERC to order transmission access to encourage competition—1992.
Standards to mitigate monopoly control in transmission announced	Order 636 issued 1992: • Comparable transmission and storage open-access required. • Functional unbundling of product and transportation sales required. • Pipeline companies allowed to make market-priced gas sales through affiliates. • Capacity release established. • Firm transportation customers get flexible receipt and delivery points. • Transportation rates usually set by SFV method.	NOPR issued March 1995: • Non-discriminatory, comparable open access required. • Public utilities must file tariffs for network, firm, and interruptible transmission. • Ancillary services must be offered under a general tariff. • Functional unbundling of accounting and billing for all **new** wholesale sales required. • Resale of transmission with access to flexible receipt and delivery points on an "as available" basis must be offered.
Access to information to support market functions	Trade press publishes spot gas prices—1989; FERC mandates individual pipeline EBB's—1992.	Market-based pricing includes requirements for EBB's—1992; EPACT requires public capability reporting—1992; FERC announces a Technical Conference on RIN's—1995.
Market characteristics evolve	Company consolidation starts—mid-1980's. Product markets active; prices transparent—1987. Robust market centers/hubs for physical trade—1993. Some private swaps and options available—1993. Futures market matures and direct consumer access to transportation is available in most States—1994. Transportation trade in formulative stage—1995.	Company consolidation starts—late 1980's. Spot and forward markets still largely restricted to utilities—1995. Neither transportation nor product prices are transparent yet—1995. Development of a futures market hindered by a lack of a standardized spot market for benchmarking. New entrants are trying to find product niches. Innovators hope to combine gas and electric market instruments for added value—1995.
Rates address risk	FERC starts trying to accommodate take-or-pay liabilities—1985. FERC's move to SFV rates for pipeline transportation shifts the risk of capital recovery to customers—1992. FERC broadens views on transition costs—1994.	FERC issues Transmission Pricing Policy and Power Pooling NOI soliciting views on risk allocation—1994. FERC propposes to allow stranded costs in transmission charges for customers purchasing transmission in place of power—1994 and 1995.

*The courts later rejected Special Marketing Programs.

FERC=Federal Energy Regulatory Commission; NGPA=Natural Gas Policy Act; PURPA=Public Utility Regulatory Policies Act; QF=PURPA qualifying facility; NRC=Nuclear Regulatory Commission; NOPR=Notice of proposed rulemaking; SFV=Straight fixed-variable; EBB=Electronic bulletin board; EPACT=Energy Policy Act; RIN=Realtime information network; and NOI=Notice of inquiry.

Source: Energy Information Administration, Office of Oil and Gas.

Electricity Industry Restructuring and Natural Gas

The restructuring of the electricity industry will increase the uncertainty of future gas demand. Changes in technology, regulation, and legislation have introduced competition into the supply of electricity and initiated an era of sweeping change in the structure of the industry.[24] The natural gas industry has already experienced similar restructuring (Table 3). Insights from restructuring of the gas industry may assist regulators and participants in electricity markets in their future decision making.

Changes in electricity regulation have been predicted to increase the amount and use of gas-fired generating capacity substantially. The recent rapid growth of nonutility generators (NUG's) and the high proportion of gas-fired generation in the NUG sector have led to expectations for substantial increases in gas demand for electric generation during the remainder of this century.[25] But the restructuring of the electricity industry could change the outlook for increases in gas use.

- **Many forecasters predict that the sale of wholesale electricity will be completely deregulated soon when access to transmission is available to all buyers and sellers in the market.**[26] Direct access to distribution systems could even allow final consumers to choose among competitive electricity vendors if State governments decide to end retail franchises.[27] Gas-fired generators can be the lowest cost and most convenient generation facilities. When the Public Utility Regulatory Policies Act of 1978 (PURPA) opened the electricity industry to NUG's, nearly half of the new generators chose gas technology. These new entrants signaled the advent of competition in electric generation. Early expectations were that more competition would further raise the demand for gas-fired generators and for natural gas.

- **But a closer analysis of the recent growth in NUG's suggests that special, one-time conditions encouraged this growth**. There are at least three conditions that encouraged NUG's to build large amounts of new, gas-fired capacity that may not hold during the restructuring of the industry. First, special PURPA privileges for nonutility producers are being reinterpreted and lessened by the Federal Energy Regulatory Commission.[28] In addition, some investor-owned electric utilities have launched an effort to persuade Congress to repeal PURPA. These actions could reduce returns and increase risks for NUG's. Second, prudence reviews under cost-of-service regulation may have discouraged building by utilities. But in the restructured environment, utilities may have more incentive to build cost effective plants. If utilities resume building, the market for NUG capacity could be smaller and more competitive. And, third, the movement towards greater reliance on market forces to determine electricity prices may increase the efficiency of use of existing capacity and, thereby, reduce total demand for new capacity in the short run.

- **The impact on gas demand of the restructuring of the electricity industry depends on transition conditions and changes in industry productivity.** The path for the transition to a competitive industry has not yet been completely defined. The issues remaining to be decided include how to allocate stranded costs;[29] how to satisfy social and environmental concerns; how to regulate any remaining monopoly functions and market power in transmission and distribution; and the extent to which the costs and benefits of the transformation will be shared among different classes of consumers.

- **Changes in industry productivity as a result of restructuring will determine the need for new generating capacity and, hence, the role of gas in meeting future electricity demand.** Restructuring could cause a number of productivity changes in the industry. For example, better utilization of existing generation and transmission could reduce the demand to build new generation. Consumers could respond to new pricing signals by reducing their electricity usage thereby eliminating some capacity expansion. New ways of integrating energy services and products could change patterns of consumer behavior and improve overall energy efficiency. And, as is demonstrated by current progress in restructuring the natural gas industry, innovative financial developments, such as open spot and futures markets, could alleviate some of the traditional needs to build plants. Any of these productivity improvements could change the industry's pattern of demand for natural gas fuel, as well as the demand for building additional gas-fired capacity.

Chapter 5 Endnotes

1. All 1994 and 1995 natural gas consumption and price data in this chapter are preliminary and come from Energy Information Administration, *Natural Gas Monthly*, DOE/EIA-0130(95/07) (Washington, DC, July 1995), pp. 5 and 7.

2. Energy Information Administration, *Monthly Energy Review*, DOE/EIA-0035(95/07) (Washington, DC, July 1995), p. 95.

3. The highest level of industrial consumption of natural gas was 8.7 trillion cubic feet (Tcf) in 1973 and the second highest was 8.3 Tcf in 1974.

4. Energy Information Administration, Form EIA-867, "Annual Nonutility Power Producer Report."

5. Energy Information Administration, *Natural Gas Annual 1993*, DOE/EIA-0131(93) (Washington, DC, October 1994), p. 4.

6. American Gas Association, Office of Policy, Analysis and International Affairs.

7. Energy consumption in the electric utility sector is total energy consumption. In the other sectors, it is net energy consumption, that is, it excludes electrical system losses. Data related to the breakout of energy consumption come from Energy Information Administration, *Monthly Energy Review*, DOE/EIA-0035(95/07) (Washington, DC, July 1995), pp. 27, 29, and 33.

8. Energy Information Administration (EIA), Office of Oil and Gas: projected growth calculated from data used for *Annual Energy Outlook (AEO95)*, DOE/EIA-0383(95) (Washington, DC, December 1994), National Energy Modeling System, Reference Case, run AEO95B.D1103942; historical growth based on *Natural Gas Annual 1992*, Vol. 2, DOE/EIA-0131(92)/2 (Washington, DC, November 1993), p. 7, and *Natural Gas Monthly*, DOE/EIA-0130(95/07) (Washington, DC, July 1995), p. 5.

9. The most recent data showing how gas was used in the residential and commercial sectors are from 1993 and 1992, respectively. Unless otherwise stated, data on this page are derived from surveys conducted by the Office of Energy Markets and End Use, specifically, EIA-457, "Residential Energy Consumption Survey" (RECS) for 1984 and 1993, and EIA-871 "Commercial Energy Consumption Survey" (CBECS) for 1983 and 1992, revised estimates. Further results from the most recent surveys may be found in Energy Information Administration (EIA), *Housing Characteristics 1993*, DOE/EIA-0314(93) (Washington, DC, June 1995) and *Commercial Buildings Energy Consumption and Expenditures 1992*, revised estimates, DOE/EIA-0318(92) (Washington, DC, April 1995). Natural gas consumption reported in these publications may differ from that in EIA's *Natural Gas Annual* and *Natural Gas Monthly* because of sampling error and differences in the items (accounts, buildings, housing units) covered by the survey. These differences are discussed in appendices to the cited publications.

10. Gas used in new homes includes both natural gas and liquefied petroleum gas. U.S. Department of Commerce, Department of the Census, *Characteristics of New Housing: 1993*, C25/93-A (Washington, DC, June 1994), pp. 20 and 37. These are the latest data available on gas in new homes.

11. The trend in industrial activity shown in Figure 21 is the index of manufacturing industrial production estimated by the Board of Governors of the Federal Reserve System.

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

13. Energy Information Administration, *Manufacturing Consumption of Energy 1991*, DOE/EIA-0512(91) (Washington, DC, December 1994). This report is based on the 1991 Manufacturing Energy Consumption Survey (MECS) of the Office of Energy Marketing and End Use. The MECS excludes small establishments, all mining, agriculture, forestry, fishing, construction, and transportation establishments, and certain nonutility generating establishments. Measures of natural gas consumption from MECS and the *Natural Gas Annual* differ because of these differences in sampling and coverage.

14. Cogenerators are one type of facility included in nonutility generators (NUG's). Most cogenerators are now "qualifying facilities" under the Public Utility Regulatory Policies Act (PURPA). NUG's, as the term is generally used, include small power and cogeneration qualifying facilities (QF's, as defined by PURPA), eligible wholesale generators (EWG's, as defined by the Energy Policy Act of 1992), and the so-called independent power producers (IPP's), which refers to any generator that is not included in regulated assets of electric utilities and is neither a QF nor an EWG.

15. Energy Information Administration, *Electric Power Annual 1993*, DOE/EIA-0348(93)(Washington, DC, December 1994) and data supplied by the Office of Coal, Nuclear, Electric and Alternate Fuels.

16. Turbine and steam-driven generators can be linked together so that waste heat from the combustion turbine is recovered and used to raise steam to power the steam generator. This combination is called a combined-cycle generator. These combination generators are currently favored by nonutilities and utilities because of their energy efficiency, flexibility, and relatively low investment cost.

17. In recent years, nonutility generators (NUG's) have been the most rapidly growing segment of the U.S. generating industry; however, NUG-owned generation started from a very small and inactive base of private generators as late as the mid-1980's. The Edison Electric Institute estimates that NUG capacity was 17,878 megawatts (MW) in 1979 and grew to 58,134 MW by the end of 1993. (See Federal Energy Regulatory Commission docket RM95-14-000, "Petition of the Edison Electric Institute for a Rulemaking Regarding Implementation of the Public Utility Regulatory Policies Act of 1978 in the Context of the Energy Policy Act of 1992.") The Energy Information Administration estimates that NUG capacity at the end of 1994 exceeded 67,000 MW. (See *Electric Power Annual 1994*, Vol. 1, DOE/EIA-0348(94)/1 (Washington, DC, July 1995) pp. 1 and 5.)

18. Energy Information Administration, *Monthly Energy Review*, DOE/EIA-0035(95/05) (Washington, DC, May 1995) and *Short-Term Energy Outlook*, DOE/EIA-0202(95/3Q) (Washington, DC, August 1995).

19. Natural gas consumed by electric utilities includes gas used in coal-, oil-, and waste-fired steam boilers to enhance combustion and flame control. Energy Information Administration, *Electric Power Annual 1994*, Vol. 1, DOE/EIA-0348(94)/1 (Washington, DC, July 1995).

20. In order to assure reliable electricity supplies, utilities may maintain their most flexible generators in a "hot-ready" state. Like a car in idle, such a generator consumes fuel but does not produce electricity until activated. Gas consumed for reliability is included in the data on utility gas consumption and may cause heat-rates to be slightly over stated.

21. Many gas and oil-fired generators are designed for oil/gas fuel switching. However, other generators are usually restricted to a single energy source by design. Historically, turnover in the generating capital stock has been slow. Large steam-fired or hydroelectric facilities can take from 5 to 15 years to construct and have productive lives that can be extended more than 45 years. Therefore, even major changes in technologies or relative fuel prices may not change average fuel consumption patterns until many years later.

22. Data are from the Energy Information Administration (EIA), *Electric Power Annual 1994*, Vol. 1, DOE/EIA-0348(94)/1 (Washington, DC, July 1995) and are estimated as of December 31, 1993.

23. Electric utility systems usually start and run generating units in ascending economic order based on the units' variable operating cost. The generating units with the lowest variable cost are committed to operations first; each succeeding unit that is brought into operation is the least costly resource remaining available to the utility. Consequently, the units at the "top of the dispatch order" are the highest variable cost units and are the units least likely to be operated.

24. Federal Energy Regulatory Commission, Notice of Proposed Rulemaking, RM95-8, "Promoting Wholesale Competition Through Open Access Non-discriminatory Transmission Services by Public Utilities," March 29, 1995.

25. See, for example, "Gas Research Institute Adopts Relatively Flat Oil Price in 15th Baseline Projections of Energy Supply and Demand Through the Year 2012," *Foster Natural Gas Report*, No. 1992 (August 18, 1994), pp. 9-11; "GRI Study Projects Slowdown in Growth of Cogeneration Capacity Through 2010," *Foster Natural Gas Report*, No. 1996 (September 1994), pp. 28-29; "Electrics May Demand Less than Thought," *Natural Gas*, Vol. 10, No. 6 (January 1994), pp. 15-16; and "Electric Power: A New Set of Markets and Demands," *Natural Gas*, Vol. 7, No. 11 (June 1991), pp. 1-5.

26. Energy Policy Act of 1992 and Federal Energy Regulatory Commission, Notice of Proposed Rulemaking, RM95-8, "Promoting Wholesale Competition Through Open Access Non-discriminatory Transmission Services by Public Utilities."

27. See, for example, Foster Associates, "INGAA Foundation 'White Paper' Examines the Role of Natural Gas in Fueling Growing Electric Power Market," *Foster Natural Gas Report*, No. 1988 (Washington, DC, July 21, 1994), p. 39.

28. Privileges under the Public Utility Regulatory Policies Act (PURPA) include exemption from State and Federal rate regulation, exemption from regulation under the Public Utility Holding Company Act, a utility obligation to offer to purchase the electricity produced by a qualifying entity at a price not to exceed the utility's avoided cost, and a utility obligation to interconnect with and supply power to a qualifying entity at a nondiscriminatory price. Recent questions on the regulations implementing PURPA are covered in a series of cases at the Federal Energy Regulatory Commission. These cases include Connecticut Light & Power Co. (1995), Southern California Edison and San Diego Gas & Electric Co. (1995), New York State Electric & Gas Corp. (1995), West Penn Power Co. (1995), CGE Fulton, L.L.C. (1995), and Turner Falls L.P. (1990).

29. Stranded costs are costs incurred under regulation that electric utilities are not able to recover after deregulation. They could include expenses for things such as power plants, long-term purchase contracts for power and fuel, and long-term liabilities for tax adjustments, pensions, and other benefits. Regulators and the industry are debating ways to construct accounting measures and to determine responsibility for stranded costs. See, for example, Federal Energy Regulatory Commission, Notice of Proposed Rulemaking, RM94-7-001, "The Recovery of Stranded Costs by Public Utilities and the Transmitting Utilities," issued March 29, 1995.

6. Gas Industry Finances

The natural gas industry was adversely affected by a number of factors in 1994, including low gas prices and rising interest rates. However, some of the negative influences were offset by the improved underlying strength of most industry segments and by strong growth in the U.S. economy. In the face of deregulation, greater competition, and a changing market structure, the industry has become more efficient and is better able to weather short-term changes in prices and the economy. However, in the long term, trends in prices and consumption will continue to have an enormous effect on the future financial performance of the industry.

Growth potential for some gas companies may be limited in the near term. Abundant supplies of gas and slower growth in demand may keep gas prices low at least through 1996. Gas prices are not expected to rise above $2 per thousand cubic feet through 1996.[1] Demand growth is expected to average about 3 percent in 1995 and 1996 compared with growth of 4 and 2 percent in 1993 and 1994, respectively.[2] Ongoing restructuring of the electricity industry could significantly affect demand growth. With the current regulatory uncertainty, plans for the construction of new gas-fired generators may be shelved, and the conversion of some plants to gas may be delayed. Also, gas may face increasing competition from electricity as that industry sector is restructured.

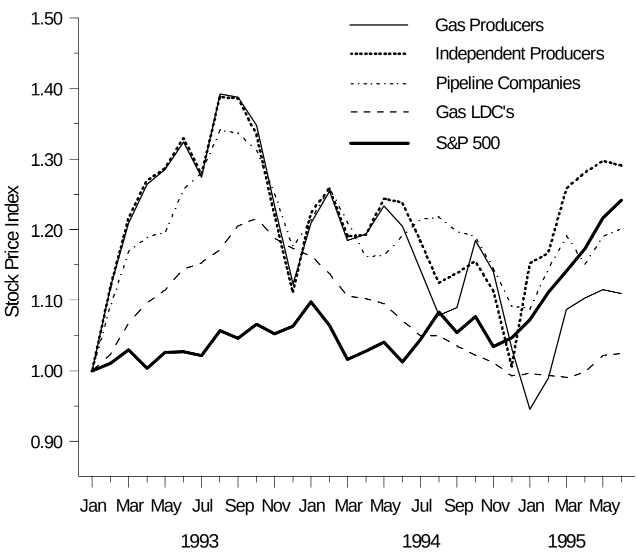
This section discusses the major influences on gas industry finances in 1994 and the first half of 1995 and considers the impact of current trends on future industry behavior and performance. Three industry segments are examined: producers, interstate pipeline companies, and local distribution companies (LDC's). Although marketers are playing an increasingly important role in the industry, lack of financial data on this segment precludes an assessment of their performance. As part of the analysis of the financial performance of these industry groups, comparisons are made with the Standard and Poor's 500 Index. These data are obtained using the Standard and Poor's Compustat data service.

The producer segment is divided into two segments: 32 independent companies and a subset of six independent gas producers who earn most of their revenues from gas production. The independent producers represented approximately 67 percent of U.S. dry gas production in 1992. The gas producers were chosen by selecting companies with a ratio of gas production to total oil and gas production greater than 50 percent, on a gas equivalent basis. Companies passing that criterion were then ranked by gas production, with companies excluded that are strongly influenced by factors other than gas. Six companies are included in the final sample of gas producers: Anadarko Petroleum, Apache Corporation, Burlington Resources, Enron Oil and Gas, Maxus Energy, and Mesa Petroleum. The major petroleum companies, such as Exxon and Shell, are not discussed in detail because their earnings are affected by many factors other than gas. For example, during 1994 the major petroleum companies reported significantly improved earnings. However, most of the increased earnings came from their chemical operations and to a lesser extent from higher oil and gas production.[3] Also, the financial performances of the major petroleum companies are affected by the results of their foreign operations and their refining and marketing activities.

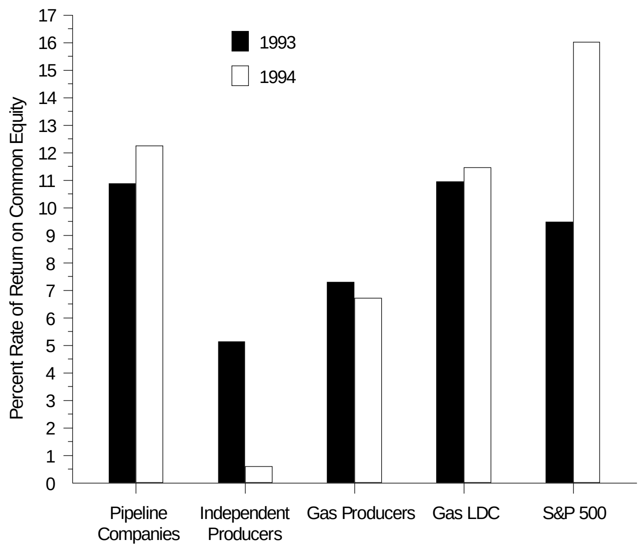
The pipeline segment is represented by the 12 interstate pipeline companies covered in last year's report, *Natural Gas 1994: Issues and Trends*. These companies accounted for 46 percent of throughput in 1993. Local distribution companies (LDC's) were divided between those that provide gas-related services only and those that provide a combination of services. The 46 gas-only service LDC's in this sample represent all such LDC's available on the Compustat database and are essentially the same as those selected for *Natural Gas 1994*. A listing of the companies that comprise each segment is presented in Appendix A.

Figure 23. Despite Low Gas Prices, Financial Indicators for Most Industry Segments Improve

Industry stocks rebound after declining in 1994



Returns by segments are mixed . . .



. . . With financial indicators for pipeline companies and LDC's showing improvement

	Producer Segment				Pipeline		Gas			
	Gas Producers		Independents		Segment		LDC Segment		S&P 500	
Financial Performance Measures	**1993**	**1994**	**1993**	**1994**	**1993**	**1994**	**1993**	**1994**	**1993**	**1994**
LT Debt as a % of Invested Capital	42.15	40.40	45.01	45.64	50.24	47.30	46.62	47.93	43.49	43.70
Times Interest Earned Ratio	2.25	2.55	1.83	1.04	2.33	2.72	2.88	2.92	3.24	4.53
Rate of Return on Common Equity (%)	7.30	6.72	5.14	0.61	10.88	12.25	10.95	11.45	9.49	16.00
Price/Earnings Ratio	23.53	33.63	26.46	35.71	16.68	14.42	14.83	13.02	16.68	13.77
Market-to-Book Ratio	2.61	2.51	2.30	2.35	1.86	1.77	1.77	1.56	2.51	2.37
Bond Rating	BBB-	BB+	BB+	BB+	BBB-	BBB	A	A	A+	A+

LDC = Local distribution company. S&P = Standard and Poor's. LT = Long term.

Notes: Gas producers are major producers who derive more than 50 percent of their production from gas. Independents are nonintegrated oil and gas companies. Pipeline companies include some companies whose dominant business is no longer transmission. Gas LDC's are LDC's that provide gas-related services only. Ratios for the S&P 500 were calculated based on data available through the S&P "Compustat" database aggregate file. For calculation of ratios, annual data were used for 1993 and 1994. Oryx Energy not included in rate of return due to large write-down from changes in accounting practices. For more information on data sources, companies used in the analysis, and calculations on measures of financial performance, refer to Appendix A.

Source: Energy Information Administration, Office of Oil and Gas, derived from: Standard and Poor's Compustat Services, Inc., "Compustat" database (August 1995).

Overview of Gas Industry Finances

The financial performance of the natural gas industry in 1994 was considerably below that of many industries. During 1994, the Standard and Poor's (S&P) 500 outperformed all segments of the natural gas industry as measured by return on equity. Higher economic growth, cost cutting, and the ability to raise prices for the first time in years led to a sizable improvement in S&P 500 companies' earnings. The performance of the S&P 500 relative to the gas industry is also reflected in the relative strength of the S&P 500 stock index. Although by the end of 1994, the S&P 500 had increased only slightly from the close of 1993, gas industry stocks were generally much lower. One of the reasons for the difference in the performance of the gas industry compared with the S&P 500 is that the industry is still adjusting to new market realities and faces considerable regulatory and economic uncertainty.

Many gas industry stocks recovered during the first half of 1995 along with the S&P 500. Producer stock prices rose the most on the prospect of higher oil prices because of the U.S. decision to sever trading ties with Iran—a major oil producer. Pipeline company stocks also rallied during the first quarter of 1995, after they reported higher earnings for 1994.

- **Between December 1993 and December 1994, indexed stock prices declined by 7 percent for independent producers, by 12 percent for gas producers, 8 percent for pipeline companies, and 13 percent for gas-only LDC's** (Figure 23). These declines were significant compared with overall stock market prices. During the first half of 1994, inflation fears and a series of interest rate hikes caused the S&P 500 index to fall. However, during the second half of the year, the S&P 500 rallied, closing out the year 0.03 percent higher than the previous year. Meanwhile, the overall economy enjoyed robust growth, with Gross Domestic Production increasing by 5.1 percent.

- **During the first half of 1995, stock prices for producers and pipeline companies rebounded, closing up 28 percent and 10 percent, respectively, by the end of June.** Improved financial results for the pipeline companies clearly contributed to their stock price upturn. Average earnings per share increased from $0.47 to $0.64 between the fourth quarter 1994 and the first quarter 1995. Increased competition, market restructuring, and uncertainty about regulatory reform continued to keep LDC stock prices low. Meanwhile, cost cutting and the perception that oil and gas prices may rise helped to bolster producer stock prices.

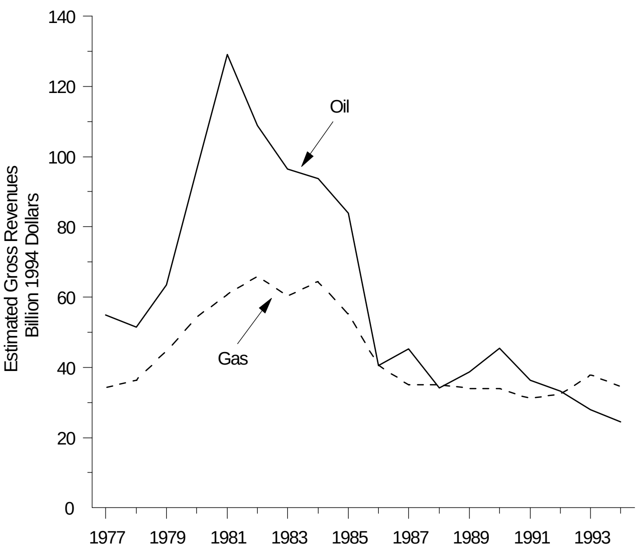
- **Falling gas prices affected profits to different degrees throughout the industry** (see table in Figure 23). Low gas and oil prices affected profits for all producers, but those concentrating on gas production were not hit as hard as the others. The rate of return for the independents declined from 5.1 percent in 1993 to 0.6 percent in 1994 (Figure 23). The rate of return for the gas producers fell from 7.3 percent to 6.7 percent over the same period. Low wellhead prices did not affect the profitability for pipeline companies and LDC's as much, although many of these companies now have greater exposure to upstream price volatility through production subsidiaries. Both pipeline companies and gas LDC's achieved higher rates of return in 1994 (Figure 23).

- **Improvements in U.S. macroeconomic performance helped to buoy the gas industry in 1994, but increases in U.S. interest rates hurt the heavily regulated LDC's.** The LDC segment is especially sensitive to interest rates because it is traditionally capital intensive and frequently assumes large amounts of debt to finance year-to-year capital improvements. Also, many investors usually sell utility stocks when interest rates rise, causing utility stocks to fall. This trend was exacerbated in 1994, by investors who also feared dividend cuts. The LDC's long-term debt ratio rose slightly from 47 percent in 1993 to 48 percent in 1994 (see table in Figure 23). An increase in housing starts contributed to expansion of the customer base for pipeline companies and LDC's. In 1994, builders selected natural gas for 68 percent of new single-family homes, resulting in new distribution lines. Also, the industry continues to be successful at adding new customers through conversions of existing homes to natural gas.

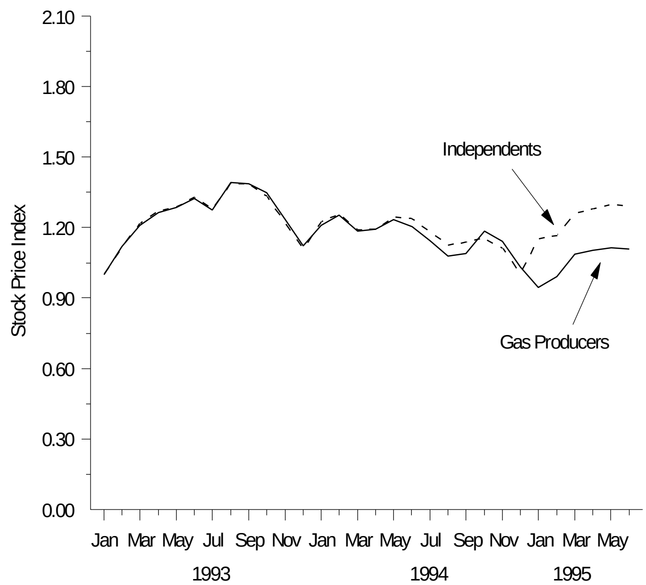
- **The introduction of unregulated natural gas services provided all segments of the industry the opportunity to earn higher returns**. The emergence of unregulated subsidiaries is playing an increasingly important role in the financial performance of industry segments. However, industry diversification into potentially higher margin unregulated services also exposes individual companies to greater risk.

Figure 24. Low Gas Prices Cause Gas Producers to Underperform the Independent Producers in the Second Half of 1994

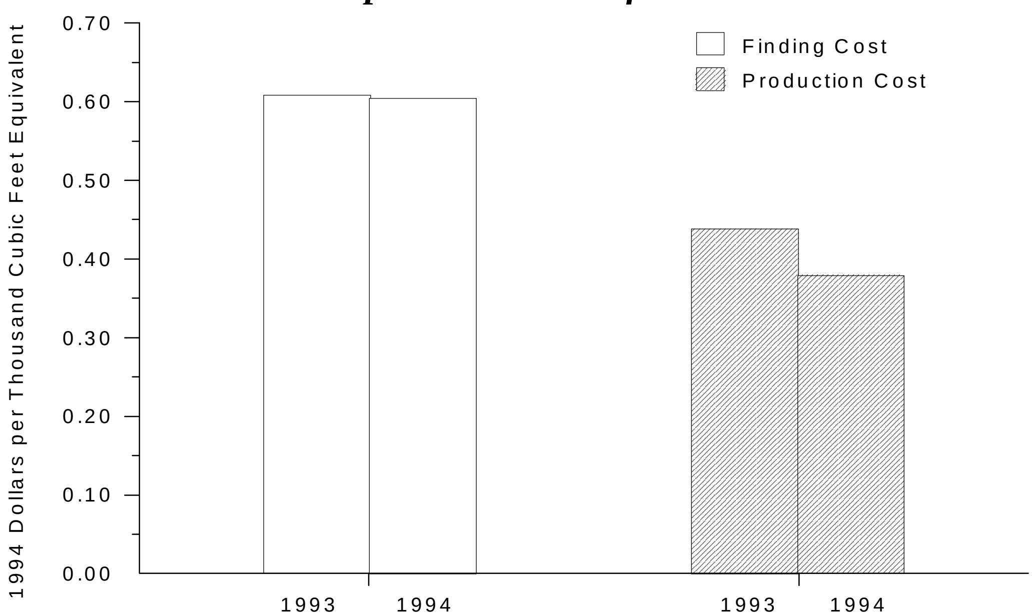
For the second year, revenues from gas outstrip oil revenues for the lower 48 States



However, gas producer stocks plummet with low gas prices in the second half of 1994



Finding costs stabilize while production costs fall



Note: Production and finding costs are for gas producers identified in Appendix A.

Sources: Energy Information Administration, Office of Oil and Gas. **Production Revenues:** derived from oil and natural gas Production and Wellhead Prices: *Annual Energy Review 1994*. **Stock Prices:** derived from Standard and Poor's Compustat Services, Inc., "Compustat" database (August 1995). **Production and Finding Costs:** derived from Arthur Andersen's Oil and Gas Reserves Disclosure database and annual company reports.

Finances: Gas Producers

Despite low wellhead gas prices in 1994, producers earned more in production revenues from gas than from oil for the second consecutive year (Figure 24). This resulted from the increase in the ratio of gas to oil production in the United States and lower oil prices. Lower operating costs positively influenced the financial performance of gas producers in 1994, although this was not sufficient to offset the fall in gas prices. Unparalleled access to markets and technology now allows producers to respond quickly to prevailing market conditions. However, plentiful gas supplies and low gas prices will require gas producers to continue their focus on operational efficiency and cost containment.

- **The gas producers' stock price performance for 1994 and the first half of 1995 reflects the steep decline in wellhead gas prices.** Stock prices of gas producers fared worse than the broad group of independents, which are less reliant on gas production for revenues (Figure 24). Gas producer stocks outperformed the independents in the early part of 1994, responding to strong sales to meet record cold weather demand during the 1993-94 heating season. However, by May their stock prices had begun to fall, while gas prices did not begin to fall until August. This suggests that the market had already begun to discount gas stocks based on record storage levels and other indicators of plentiful supplies.

- **Despite low prices, continued improvements in upstream efficiency helped sustain cash flow and profitability for some gas producers**. Low prices caused the gas producers' net earnings to decline and their return on equity to fall. However, increased efficiency has enabled some gas producers to supply more gas at lower prices. They have reduced the impact of low prices on their profits by reducing their production costs (Figure 24).

- **The sample of gas producers increased production by 7.8 percent in 1994 to 1.1 trillion cubic feet (Tcf), while total U.S. gas production increased by 3 percent to 18.8 Tcf.** Some of the production increases came from discoveries of new reserves, but a significant portion came as a result of changes in State regulation and improved inventory control practices. For example, the Kansas Corporation Commission and The Texas Railroad Commission increased field production allowables in 1994. Anadarko Petroleum reported that as a result of the increased allowables, it significantly increased production from the Hugoton field in Kansas and the Panhandle field in west Texas. However, the company also reported that some high-cost wells were shut in during the latter half of the year when gas prices fell below operating costs.

- **Through more efficient exploration and development, producers can quickly bring gas supplies to market in response to short-term price increases.** For example, when prices rose 17 percent in 1993, additional production from formerly curtailed and shut-in wells boosted Anadarko Petroleum's net revenues from U.S. and Canadian gas production by 26 percent. The additional earnings funded new drilling and field development, and reserve discoveries shot up from 41 to 226 billion cubic feet (Bcf). The company now produces 20 percent more gas than in 1992.[4] Apache Corporation increased gas production by 41 percent in 1994, to 153 Bcf, while it increased its natural gas reserves from 848 Bcf to 1,016 Bcf.[5]

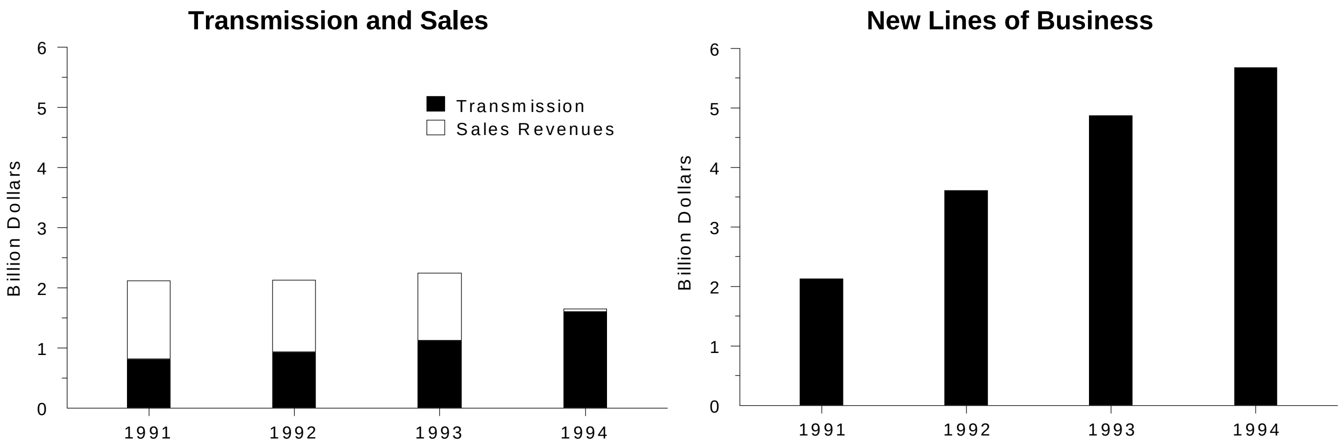
- **Many companies face increased risk from holding high-cost reserve inventories.** Holding high-cost reserves during periods of declining prices exposes producers to significant risk. More producers are booking new low-cost reserves because of a long-term fall in finding costs, which gives them a competitive advantage over producers with large inventories of high-cost reserves. This is especially true given the flexibility in delivery arrangements, which has created heightened competition among producers to provide gas at the lowest market price.

- **Many gas producers continue to benefit from the Unconventional Gas Tax Credit although it is no longer available for new wells.**[6] Burlington Resources estimates that it earned $84 million from unconventional gas tax credits in 1994, 13 percent of its estimated gross (gas production) revenues of $634 million. Amoco Corporation earned $174 million in tax credits, the bulk of which was in unconventional tax credits.[7]

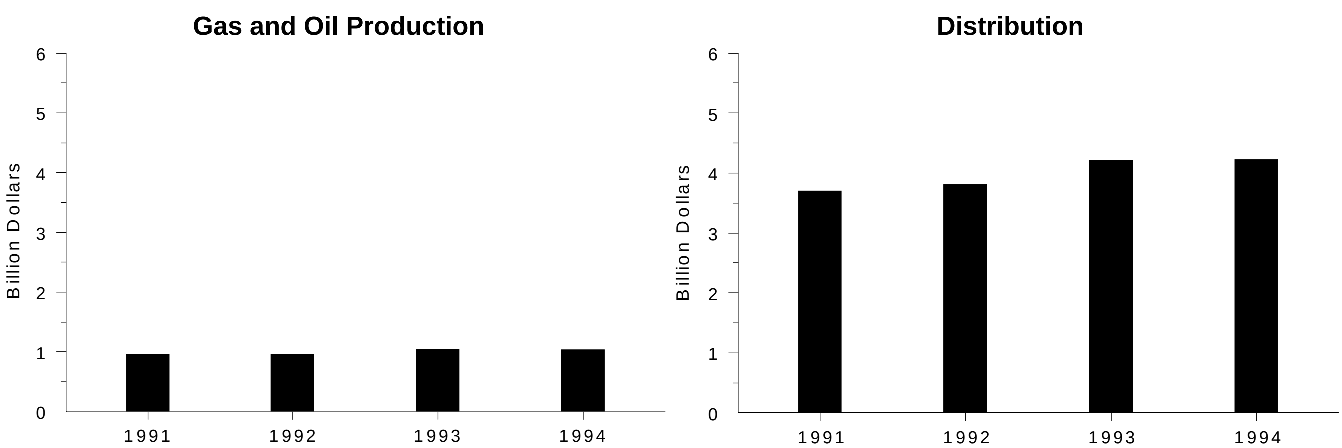
- **Continued low wellhead prices increase the pressure on producers to continue cost cutting and improve efficiency.** In light of continued low gas prices, some producers are reporting scaled-back capital spending for 1995. For example, Maxus Energy reduced exploration spending from $18.5 million to $16.8 million between the first half of 1994 and the first half of 1995.[8] Other gas producers reporting reduced expenditures for the first half of 1995 include Anadarko Petroleum (from $224.4 million to $127 million), Burlington Resources ($539 million to $302 million), and Apache Corporation ($163 million to $142 million).

Figure 25. Pipeline Companies Earn More Through Diversification

Operating revenues for six companies illustrate growing interest in providing nonregulated services . . .



. . . While revenues from other services remain unchanged



FERC Order 636 spurs growth in nonregulated business areas

	Nonregulated Businesses				
Pipeline Company	**Natural Gas Marketer**	**Power Generation Plants**	**Electric Power Marketer**	**Market Center Owner**	**Gathering & Processing Services**
Coastal Corporation	X	X	X	X	X
Consolidated Natural Gas Company	X	X	X	X	
Noram Energy Corporation	X		X	X	X
Panhandle Eastern Corporation	X		X		X
Transco Energy Company	X		X		X

Note: The six companies in the revenue sample include CNG Corp., Columbia Gas System, KN Energy Corp., Panhandle Eastern, Questar Corp., and Williams Companies. These companies account for 12 percent of throughput based on 1993 data. The five companies shown in the table were selected based on data from company annual reports.

Source: **Transmission and Sales Revenues:** Energy Information Administration, Office of Oil and Gas: derived from: Federal Energy Regulatory Commission, FERC Form 11, “Natural Gas Pipeline Company Monthly Statements.” **Other Revenues:** Company annual reports. **Nonregulated Business Areas:** Company annual reports and press releases.

Finances: Interstate Pipeline Companies

The financial performance of the interstate natural gas pipeline companies during the first full year of operation under Order 636 was affected by a number of factors, including lower wellhead prices, mild weather conditions, and growth in unregulated services. Regulatory uncertainty is still a problem for interstate pipeline companies who continue to incur transition costs associated with restructuring and the costs of stranded investments. With transmission and sales revenues declining because of changing tariff structures and the unbundling of their sales and transportation activities, many companies are now focusing on providing unregulated services. The pipeline companies have been active in seeking unregulated business opportunities through consolidations or spindowns of already existing services. These unregulated businesses made substantial contributions to operating revenues in 1994 (Figure 25).

- **Even though few pipeline companies are still significant suppliers of natural gas, low natural gas prices hurt the pipeline group last year.** Pipeline companies with exploration, production, and marketing subsidiaries were influenced by lower natural gas prices and milder weather conditions. Coastal, Enron, Questar, and Sonat all experienced well shut-ins during 1994 when prices fell below production costs. Also, although pipeline throughput grew modestly, it was hampered by milder-than-normal weather for most of 1994. The composition of gas consumption also changed last year. Throughput to electric power generators grew, in large part because of drought conditions in the Northwest and low gas prices, while growth in throughput to residential and small commercial customers was lower.

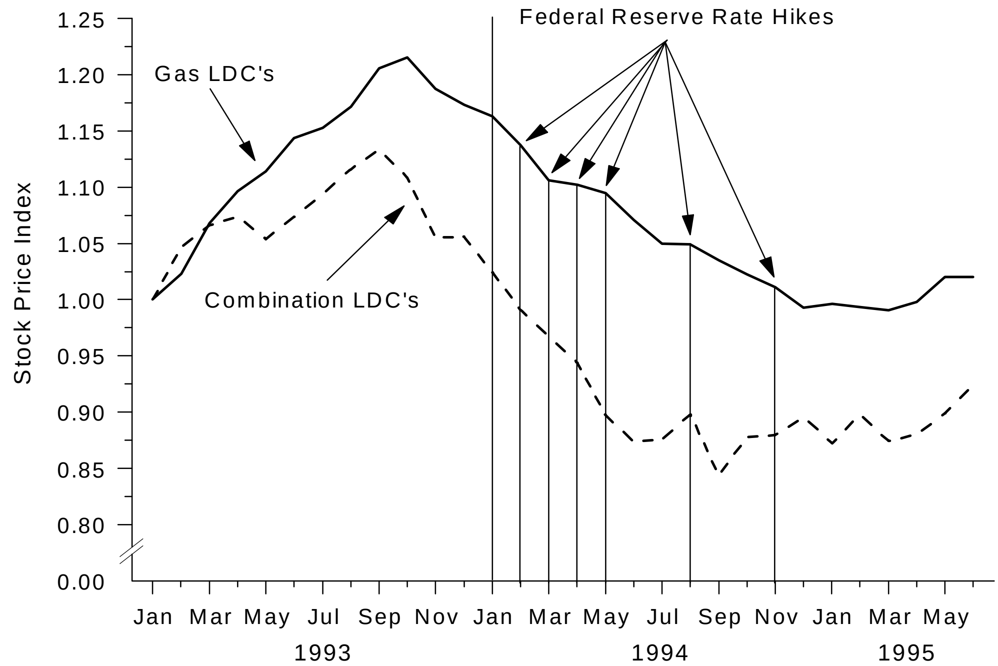
- **Growth in the development of unregulated services is becoming more important to the financial performance of the pipeline companies**. Many pipeline companies are following a policy of "energy service diversification" and have either formed new subsidiaries to offer unregulated services or sought suitable companies to acquire. Some examples of unregulated services currently offered by pipeline companies are gas marketing, independent power production, gas processing, exploration and production, and gas gathering.

- **It is increasingly difficult for pipeline companies to increase throughput by expanding their systems.** As the gas industry gets better at routing gas between locations and using high-deliverability storage, pipeline companies face the increasing risk that customers will no longer need the same amount of firm transportation capacity they contracted for originally. This is often referred to as the stranded investment problem, and much of the costs associated with these investments will initially be recovered from remaining customers. However, as energy markets become more competitive, it will be increasingly difficult for pipeline companies to pass these costs along and hence risk the loss of even more customers. In some instances, the problem will probably be resolved through the early retirement of some investments and a reduction in the rate of return (placing downward pressure on future stock prices). In other instances, pipeline companies will be motivated to cut internal costs to retain customers and also to move into other lines of business.

- **Increasing competition, particularly in unregulated services, is driving industry consolidation**. Consolidation enables pipeline companies to access in-place pipeline networks and established service businesses. It also enables them to reduce price and market risk through business diversification. Mergers completed by Panhandle Eastern, Williams, and KN Energy all contributed to existing businesses while adding additional service subsidiaries. In October 1994, Panhandle Eastern acquired Associated Natural Gas Corporation. This purchase provided Panhandle with a new electric power marketing subsidiary (Associated Power Services Incorporated) and substantially increased Panhandle's existing marketing subsidiary (One Source Corporation) and gathering and processing subsidiary (Centana). Panhandle also gained access to Canadian markets through Associated's established marketing offices in Calgary and Spokane, Washington. The Williams purchase of Transco provided Williams with new, unregulated gas and electric power marketing affiliates. Also, transmission, gathering and processing assets acquired from Transco substantially augmented the existing Williams system. KN Energy's acquisition of American Oil and Gas provided the company with access to supply basins in Texas, as well as sizable additions to marketing, gathering, and processing services.

Figure 26. Interest Rate Hikes Hit LDC Stocks

Interest rate hikes and regulatory uncertainty cause LDC stocks to fall in 1994



Increased diversification may improve the performance of some companies in the future

Local Distribution Company	Pipeline/ Gathering	Exploration & Production	Electric Utility	Other
	New Lines of Business			
Brooklyn Union Gas	X	X		Market Center (Sole Owner)
Energen Corp.		X		Retail Appliance (Sole Owner)
Equitable Resources	X	X		Natural Gas Marketing
MCN Corporation	X	X		Natural Gas Marketing Computer Services
National Fuel Gas	X	X		Natural Gas Marketing Market Center (50 Percent Owner)
New Jersey Resources		X		Market Center Company (5 Percent Owner)
ONEOK, Inc.	X	X		
Southwest Gas	X			Primerit Bank (Sole Owner)
Utilicorp	X	X	X	Natural Gas Marketing
Washington Energy Company		X		Coal Operations

Sources: Company annual reports. **Stock Prices:** derived from Standard and Poor's Compustat Services, Inc., "Compustat" database (August 1995).

Finances: Local Distribution Companies

Stock prices for the local distribution company (LDC) segment of the natural gas industry significantly underperformed other industry segments for most of 1994 and the first half of 1995. This stemmed from the sharp increases in short-term interest rates, reductions in dividends, and milder-than-normal weather. Also, LDC's are beginning to feel the initial effects of deregulation and industry restructuring. They now face increased competition and greater risk. This will only continue as regulation and market structure continue to change.

- **LDC dividends are a target of cost-cutting strategies.** Traditionally, LDC stocks paid comparatively high, stable dividends. In the increasingly competitive distribution market, however, LDC's are seeking ways to cut costs and increase net cash flows. Maintaining high dividend yields increases the cost of providing distribution service and uses earnings that could otherwise be invested in new business. To remain competitive in the post-636 environment, LDC's are diversifying by providing a variety of new services. Cutting dividends has freed up internal resources to fund these new business projects, but has also resulted in lower stock prices.

- **During 1994, LDC stock prices fell as the Federal Reserve nearly doubled the Federal Funds rates.** Rising interest rates made higher yielding investments look more attractive and adversely influenced the stock prices of many LDC's (Figure 26). High interest rates also increase the expected cost of doing business for gas distributors, which are very capital intensive.

- **Stock prices of gas LDC's were less volatile than stocks of combination utilities and significantly outperformed them in 1994 and the first half of 1995** (Figure 26). In 1994, stocks of gas LDC's traded within a much narrower price range compared with combination utilities. There was a 13-percent difference, on average, between the high and low stock prices for gas LDC's compared with a 21-percent range for combination utilities. The restructuring of the electric utility industry has created considerable uncertainty about the future profitability of this portion of their business. Electric utilities are facing greater competition, with large customers pressing for lower rates and States permitting buyers to bypass their local utilities. Many utilities are reducing staff and closing inefficient plants. As part of the drive for efficiency, the combination utilities are seeking cheaper methods to raise investment capital. Previously they would raise money in the bond markets and pay out a significant portion of their earnings as dividends to stockholders. In the current business climate, more utilities are funding capital spending out of cash flow and cutting their dividends. For example, in May 1994, FPL Group, the holding company of Florida Power and Light, cut its dividend 32 percent from $2.48 to $1.68. Other combined utilities that have cut dividends significantly in the past few years include Pacific Gas and Electric, Niagara Mohawk, and New York State Electric and Gas. Many shareholders are anticipating that more utilities will follow suit.[9]

- **Gas LDC's that have aggressively moved into new lines of business have experienced significant growth in their stock price during the past couple of years.** With the gradual introduction of citygate unbundling (see "State Regulatory Issues," Chapter 3), LDC's must contend with more competition in their service territories. Increased competition has prompted many LDC's to diversify into unregulated energy-related businesses and to provide related services. For example, Utilicorp has positioned itself for a deregulated environment by launching a variety of service businesses in the past decade. Utilicorp has spun off an unregulated marketing affiliate (Aquila Energy Subsidiary), a gas gathering and processing affiliate, and a gas and oil production affiliate. In early 1995 Utilicorp began marketing energy products and services nationwide. MCN Corporation is another example of an LDC that has diversified into unregulated activities, including computer operations, gas marketing, cogeneration, gas gathering, gas processing, and exploration and production. Success in these activities has enabled MCN to offset setbacks in its utility business from lower allowed rates of return.[10] While stock prices for the group of utilities declined by 12.7 percent in 1994, MCN Corporation's stock price increased by 3.4 percent.

Chapter 6 Endnotes

1. Energy Information Administration, *Short Term Energy Outlook 1995*, DOE/EIA-0202(95/3Q) (Washington, DC, August 1995).
2. Energy Information Administration, *Monthly Energy Review*, DOE/EIA-0035(95/04) (Washington, DC, July 1995).
3. Energy Information Administration, *U.S. Energy Industry Financial Developments 1994 Fourth Quarter*, DOE/EIA-0543(94/4Q) (Washington DC, April 1995), p. 3.
4. Anadarko Petroleum, *1994 Annual Report.*
5. Apache Corporation, *1994 Annual Report*.
6. To qualify for Section 29 Unconventional Gas Tax credits on production from coalbed methane and tight sand wells, producers had to begin drilling before a January 1, 1993 deadline. However, production from these wells qualifies for the tax credit until December 31, 2002.
7. Amoco Corporation, *1994 Annual Report*. Also from Energy Information Administration, Office of Energy Markets and End Use.
8. Maxus Energy, Form 10-Q, "Quarterly Report Pursuant to Section 13 or 15(C) of the Securities Exchange Act of 1934" (Quarterly period ending June 30, 1995).
9. "When Utility Dividends Drop, What's a Shareholder to Do?" *New York Times* (Sunday April 30, 1995).
10. MCN's exploration and production arm has shown strong growth recently. Since they initiated investments in upstream activities in 1991, capital expenditures have risen to over $100 million in 1994.

Appendix A

Financial Analysis Methodology

Appendix A

Financial Analysis Methodology

This appendix presents the methodology used to estimate the measures of financial performance presented in Chapter 6. The measures were calculated for each industry segment (gas producers, independent producers, interstate pipeline companies, and local distribution companies), based on a sample of companies contained within the Standard and Poor's (S&P) Compustat database. Both annual and quarterly data items from the database have been used in this analysis. For the calculation of financial ratios used in the chapter, annual data were used from 1993 and 1994. Average stock prices were calculated based on monthly stock prices available from January 1993 through June 1995. Aggregation of variables and calculations of financial measures follow the procedures suggested by Standard and Poor's.

Segment Sample of Companies

The analysis was conducted for the major segments of the natural gas industry based on availability of data within the Compustat database for 1993 and 1994. The companies that comprise the sample for each of the segments analyzed are listed in Table A1, along with corresponding stock ticker symbols, S&P industry code numbers, and S&P company codes.

The producer segment of the industry was divided between independent producers and gas producers. The independent producer sample represents 67 percent of the 1992 dry gas production in the United States by publicly traded independent producers. The gas producer segment was chosen by selecting the top six gas producers with a ratio of gas production to total oil and gas production greater than 50 percent, on a gas-equivalent basis.

The interstate pipeline company segment represents parent companies of all interstate pipeline companies available on the Compustat database.

Local distribution companies (LDC's) were divided between those that provide gas-related services only and those that provide a combination of services. However, because the results of the combination-service LDC's did not differ greatly from those of the gas-only service LDC's, this group was excluded from the analysis. The gas-only service LDC's in this sample represent all such LDC's available on the Compustat database.

Lastly, S&P 500 data were used in the analysis based on data available through the Compustat Industrial Database However, the ratios reported for the S&P 500 may differ from those reported in Standard and Poor's publications, because of differences in aggregation methodology. The methodology used in this analysis isbased on a simple aggregation of S&P 500 company data. In contrast, Standard and Poor's publications use market valuation weighting factors to derive the ratios.

Calculation of Financial Performance Measures

The items selected from the Compustat database, along with the corresponding annual and quarterly S&P item number, for use in the calculation of the measures of financial performance for each segment sample of the U.S. natural gas industry are found in Table A2. The calculations for these measures are presented below. Note that the summations in each calculation refer to the aggregation of companies within each segment.

Adjusted Average Stock Price

In the Compustat quarterly database, stock price data are available for each month of the quarter. The monthly adjusted average stock price is calculated using quarterly high and low stock price variables for each month of the quarter (quarterly items 63-68), the quarterly common shares outstanding (quarterly item 61), and the quarterly adjustment factor (quarterly item 17). The adjustment factor is a ratio that adjusts per-share data, such as stock prices for all stock splits and stock dividends that occur subsequent to the end of a given year. The average adjusted stock price presented is for December of each year. For each segment, from January 1992 to June 1995, the following calculation was used for each month:

$$AASP = \frac{\sum [(P_h + P_l) * CSO]}{2 * \sum (CSO * ADJ)}$$

where,

AASP	=	Adjusted Average Monthly Stock Price
P_h	=	Company Stock Monthly Price-High
P_l	=	Company Stock Monthly Price-Low
CSO	=	Quarterly Common Shares Outstanding
ADJ	=	Company Quarterly Adjustment Factor

In some periods, the items CSO and ADJ were unavailable. As a proxy, for some companies, values for CSO and ADJ were taken for the last available period.

Average Bond Rating

For each year, a weighted average S&P bond rating was calculated for each segment based on net sales.

$$ABR = \sum \left[\frac{NS}{\sum (NS)} * BRV\right]$$

where,

ABR	=	Average Bond Rating
NS	=	Net Sales (annual item 12)
BRV	=	Bond Rating Value (annual item 280)

Long-Term Debt as a Percent of Invested Capital

For each segment and year, this ratio was calculated as follows:

$$LTDCAP = \frac{\sum LTD}{\sum INCAP}$$

where,

LTDCAP	=	Long-Term Debt as a Percent of Invested Capital
LTD	=	Long-Term Debt (annual item 9)
INCAP	=	Total Invested Capital (annual item 37)

Times Interest Earned Ratio

For each segment and year, this ratio was calculated as follows:

$$TIE = \frac{\sum (INTEX + PTXIN)}{\sum INTEX}$$

where,

TIE	=	Times Interest Earned Ratio
INTEX	=	Interest Expense (annual item 15)
PTXIN	=	Pre-tax Income (annual item 170)

Return on Common Equity

For each segment and year, the rate of return on common equity was calculated as follows:

$$ROR = \frac{\sum NI}{\sum TCE}$$

where,

ROR	=	Rate of Return on Common Equity
NI	=	Net Income (annual item 172)
TCE	=	Total Common Equity (annual item 60)

Price/Earnings Ratio

For any given year, companies with negative net income are excluded from the calculation of Price/Earnings ratio. Thus, for each segment and year, the following formula applies for firms with NI > 0,

$$PE = \frac{\sum [(P_h + P_l) * CSO]}{2 * \sum (NI)}$$

where,

PE	=	Price/Earnings Ratio
P_h	=	Company Stock Price-High (annual item 22)
P_l	=	Company Stock Price-Low (annual item 23)
CSO	=	Common Shares Outstanding (annual item 25)
NI	=	Net Income (annual item 172)

Market/Book Value Ratio

The market/book value ratio was calculated for each segment as follows:

$$MB = \frac{\sum [(P_h + P_l) * CSO]}{2 * \sum (TCE)}$$

where,

MB	=	Market/Book Value Ratio
P_h	=	Company Stock Price-High (annual item 22)
P_l	=	Company Stock Price-Low (annual item 23)
CSO	=	Common Shares Outstanding (annual item 25)
TCE	=	Total Common Equity (annual item 60)

Table A1. Natural Gas Industry Segment Sample Companies

	Company Stock Ticker Symbol	S&P Industry Code	S&P Company Code
Gas Producers			
Anadarko Petroleum Corp.	APC	1311	32511
Apache Corp.	APA	1311	37411
Burlington Resources Inc.	BR	1311	122014
Enron Oil & Gas	EOG	1311	293562
Maxus Energy Corp.	MXS	1311	577730
Mesa Inc.	MXP	1311	590911
Producers (Independents)			
Alamco Inc.	AXO	1311	10742
Anadarko Petroleum Corp.	APC	1311	32511
Apache Corp.	APA	1311	37411
Basin Expl. Inc.	BSNX	1311	70107
Brown (Tom), Inc.	TMBR	1311	115660
Burlington Resources Inc.	BR	1311	122014
Cabot Oil & Gas Corp - CLA	COG	1311	127097
Chieftain International Inc.	CID	1311	16867C
CODA Energy	CODA	1311	191886
Crystal Oil Company	COR	1311	229385
DEKALB Energy Company	ENRGB	1311	244874
Dorchester Hugoton - LP	DHULZ	1311	258205
Enron Oil & Gas	EOG	1311	293562
Forest Oil Corp.	FOIL	1311	346091
Hallwood Cons. Res. Corp.	HCRC	1311	40636V
Hallwood Energy Prtnr. - LP	HEP	1311	40636P
Louisiana Land & Exploration	LLX	2911	546268
Maxus Energy Corp.	MXS	1311	577730
Mesa Inc.	MXP	1311	590911
Noble Affiliates Inc.	NBL	1311	654894
Norcen Energy Res.	NCN	1311	655492
Nuevo Energy Co.	NEV	1311	670509
Oryx Energy Co.	ORX	1311	68763F
Parker & Parsley Petroleum	PDP	1311	701018
Plains Petroleum Company	PLP	1311	726529
Pogo Producing Co.	PPP	1311	730448
Presidio Oil - CLA	PRS.A	1311	741016
Sage Energy Co.	6041C	1311	786629
Samson Energy Co. LP	SAM	1311	796022
Sante Fe Energy Resources	SFR	1311	802012
Snyder Oil Corp.	SNY	1311	833482
St. Mary Land & Explor. Co.	MARY	1311	792228
Tide West Oil Company	TIDE	1311	886355
Wainoco Oil Corp.	WOL	2911	930676
Interstate Pipeline Companies			
Coastal Corp.	CGP	4922	190441
Columbia Gas System	CG	4923	197648
Consolidated Natural Gas Co.	CNG	4923	209615
El Paso Natural Gas Co.	EPG	4922	283695
Enron Corp.	ENE	4923	293561
KN Energy Inc.	KNE	4923	482620
Noram Energy Corp	NAE	4923	655419
Panhandle Eastern Corp.	PEL	4922	698462
Questar Corp.	STR	4923	748356
Sonat Inc.	SNT	4922	835415
Transco Energy Co.	E	4922	893532
Williams Cos Inc.	WMB	4922	969457

	Company Stock Ticker Symbol	S&P Industry Code	S&P Company Code
Local Distribution Companies (Gas Only)			
Allegheny & Western Energy	ALGH	4924	17227
Atlanta Gas Light Co.	ATG	4924	47753
Atmos Energy Corp	ATO	4924	49560
Bay State Gas	BGC	4924	72612
Berkshire Gas Co.	BGAS	4924	84653
Brooklyn Union Gas Co.	BU	4924	114259
Cascade Natural Gas Corp.	CGC	4924	147339
Chesapeake Utilities Corp.	CPK	4923	165303
Colonial Gas Co.	CGES	4924	195674
Connecticut Energy Corp.	CNE	4924	207567
Connecticut Natural Gas Corp.	CTG	4924	207651
Corning Natural Gas Corp.	3CNNG	4923	219381
Delta Natural Gas Co. Inc.	DGAS	4923	247748
Eastern Enterprises	EFU	4924	27637F
Energen Corp.	EGN	4924	29265N
EnergyNorth Inc.	ENNI	4924	292925
Enserch Corp.	ENS	4923	293567
Equitable Resources Inc.	EQT	4923	294549
Essex County Gas Co.	ECGC	4924	296772
Fall River Gas Co.	3FALL	4924	306279
Indiana Energy Inc.	IEI	4924	454707
Laclede Gas Co.	LG	4924	505588
MCN Corp.	MCN	4924	55267J
Mobile Gas Service Corp.	MBLE	4924	607369
National Fuel Gas Co.	NFG	4924	636180
National Gas & Oil Co.	NLG	4923	636195
New Jersey Resources	NJR	4924	646025
NICOR Inc.	GAS	4924	654086
North Carolina Natural Gas	NCG	4923	658221
Northwest Natural Gas Co.	NWNG	4924	667655
NUI Corp.	NUI	4924	629430
Oneok Inc.	OKE	4923	682678
Pacific Enterprises	PET	4924	694232
Pennslvania Enterprises Inc.	PENT	4932	708720
Peoples Energy Corp.	PGL	4924	711030
Piedmont Natural Gas Co.	PNY	4924	720186
Providence Energy Corp.	PVY	4924	743743
Public Service Co. of N.C.	PSNC	4924	744516
Roanoke Gas Co.	3RGCO	4924	769858
South Jersey Industries	SJI	4924	838518
Southeastern Michigan Gas Entrpr.	SMGS	4924	841825
Southern Union Co.-New	SUG	4924	844030
Southwest Gas Corp.	SWX	4923	844895
Southwestern Energy Co.	SWN	4923	845467
United Cities Gas Co.	UCIT	4924	909823
Valley Resources Inc.	VR	4924	920062
Washington Energy Co.	WEG	4924	938815
Washington Gas Light Co.	WGL	4924	938837
WICOR Inc.	WIC	4924	929253
Wisconsin Southern Gas Co.	WISC	4924	977045
Yankee Energy Sys Inc.	YES	4924	984779

	Company Stock Ticker Symbol	S&P Industry Code	S&P Company Code
Local Distribution Companies (Combination Gas and Electric)			
Baltimore Gas & Electric	BGE	4931	59165
Central Hudson Gas & ELectric	CNH	4931	153609
Cilcorp Inc.	CER	4931	171794
Cinergy Corp.	CIN	4931	172474
Cincinnati Gas & Electric	CIN	4931	172070
CIPSCO Inc.	CIP	4931	125539
Citizens Utilities	CZN.A	4931	177342
CMS Energy Corp.	CMS	4931	125896
Commonwealth Energy System	CES	4931	202800
Consolidated Edison of NY	ED	4931	209111
Consumers Power Co.	CMS1	4931	210615
Delmarva Power & Light	DEW	4931	247109
DPL Inc.	DPL	4931	233293
Florida Public Utilities Co.	FPU	4931	341135
IES Industries Inc.	IES	4931	44949M
Interstate Power Co.	IPW	4931	461074
Iowa-Illinois Gas & Electric	IWG	4931	462470
LG&E Energy Corp.	LGE	4931	501917
Long Island Lighting	LIL	4931	542671
Madison Gas & Electric Co.	MDSN	4931	557497
MDU Resources Group Inc.	MDU	4932	552690
Midwest Resources	MWR	4931	598374
Minnesota Power & Light	MPL	4931	604110
Montana Power Co.	MTP	4931	612085
New York State Electric & Gas	NGE	4931	649840
Niagara Mohawk Power	NMK	4931	653522
NIPSCO Industries Inc.	NI	4931	629140
Northern States Power-MN	NSP	4931	665772
Northwestern Public Service Co.	NPS	4931	668231
Orange & Rockland Utilities	ORU	4931	684065
Pacific Gas & Electric	PCG	4931	694308
Pacificorp	PPW	4931	695114
Public Service Co. of Colorado	PSR	4931	744448
Public Service Co. of N. Mexico	PNM	4931	744499
Public Service Entrp.	PEG	4931	744573
Rochester Gas & Electric	RGS	4931	771367
San Diego Gas & Electric	SDO	4931	797440
Scana Corp.	SCG	4931	805898
Sierra Pacific Res.	SRP	4931	826425
Southern Indiana Gas & Elec	SIG	4931	843163
St. Joseph Light & Power	SAJ	4931	790654
UGI Corp.	UGI	4932	902681
Unitil Corp.	UTL	4931	913259
Utilicorp United Inc.	UCU	4931	918005
Washington Water Power	WWP	4931	940688
Western Resources Inc.	WR	4931	959425
Wisconsin Energy Corp.	WEC	4931	976657
Wisconsin Public Service	WPS	4931	976843
WPL Holdings Inc.	WPH	4931	929305

*Denotes companies with consistent time series bond rating information used in segment bond rating calculations.

Source: Standard and Poor's Compustat Services, Inc. "Compustat" database (August 1995).

Table A2. Compustat Variables Used in Analysis

Variable Name	Annual Item Number	Quarterly Item Number
Long-Term Debt	9	N/A
Net Sales	12	N/A
Interest Expense	15	N/A
Yearly High Stock Price	22	N/A
1st Month of Quarter High Stock Price	N/A	63
2nd Month of Quarter High Stock Price	N/A	64
3rd Month of Quarter High Stock Price	N/A	65
Yearly Low Stock Price	23	N/A
1st Month of Quarter Low Stock Price	N/A	66
2nd Month of Quarter Low Stock Price	N/A	67
3rd Month of Quarter Low Stock Price	N/A	68
Common Shares Outstanding	25	61
Adjustment Factor	27	17
Total Invested Capital	37	N/A
Total Common Equity	60	N/A
Pre-Tax Income	170	N/A
Net Income	172	N/A
S&P Bond Rating	280	N/A

Source: Standard and Poor's Compustat Services, Inc. "Compustat" database (August 1995).